BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2019-224-E
DOCKET NO. 2019-225-E

In the Matter of:	)	
	)	
South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC	))))))	**PROPOSED ORDER OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

[*RENEWED MOTION TO STRIKE GRANTED]*

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I. INTRODUCTION

The matter comes before the Public Service Commission of South Carolina (the "Commission" or "PSC") pursuant to the South Carolina Energy Freedom Act ("Act 62"), S.C. Code Ann. § 58-37-40, and Order No. 98-502 for consideration of the 2020 Integrated Resource Plans ("2020 IRPs") filed respectively by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies"). As required by Act 62, the Companies filed the 2020 IRPs on September 1, 2020.[1] The 2020 IRPs were the Companies' first IRPs filed under Act 62.

In 2019, the General Assembly extensively amended the IRP approval process in Act 62. Since 1992, integrated resource plans ("IRPs") were approved in "filing only" proceedings as the law did not mandate the Commission to conduct any review or to take any action related to a utility's IRP.[2] Now, the Commission is authorized to review the utility's IRP in a contested case proceeding with the mandatory participation of the Office of Regulatory Staff ("ORS") and the right for any interested persons to intervene. S.C. Code Ann. § 58-37-40(C)(1).

The General Assembly expresses its purpose and policies through the statutes it enacts and, as such, a statute must be given a reasonable and practical construction consistent with the purpose and policy expressed in the statute. *Davis v. Nations Credit Fin. Servs. Corp.*, 326 S.C. 83, 484 S.E.2d 471 (1997); *Georgia-Carolina Bail Bonds, Inc. v. Cty. of Aiken*, 354 S.C. 18, 22-23, 579 S.E.2d 334, 336 (Ct. App. 2003); *Daisy Outdoor Adver. Co. v. South Carolina Dep't of Transp.*, 352 S.C. 113, 120, 572 S.E.2d 462, 466 (Ct. App. 2002); *Stephen v. Avins Constr. Co.*, 324 S.C. 334, 478 S.E.2d 74 (Ct. App. 1996). Act 62 makes clear that the General Assembly wants the

[1] The Companies filed limited corrections to their 2020 IRPs on November 6, 2020.
[2] DEC and DEP most recently filed IRP Updates on September 4, 2019, in Docket Nos. 2019-224-E and 2019-225-E.

process, development, and now review of a utility's IRP to be substantive, meaningful and of value for the public's interest.

South Carolina Code Section 58-37-40, as amended, provides a detailed list of required elements and analyses to be included in the utility's IRP. The Commission shall approve an electrical utility's IRP if it determines that the proposed IRP "represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed" by the Commission. S.C. Code Ann. § 58-37-40(C)(2). To determine whether the Company's IRP is the most reasonable and prudent means of meeting its energy and capacity needs, the Commission is directed to consider, in its discretion, whether the plan appropriately balances the following factors: (a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins; (b) consumer affordability and least cost; (c) compliance with applicable state and federal environmental regulations; (d) power supply reliability; (e) commodity price risks; (f) diversity of generation supply; and (g) other foreseeable conditions that the commission determines to be for the public interest. *Id*.

Pursuant to S.C. Code Ann. § 58-37-40(C)(2) and based on the Commission's review of the entire record in these proceedings, the Commission hereby approves the 2020 IRPs filed by the Companies. As further explained herein, the Companies, ORS, and intervening parties including the Carolinas Clean Energy Business Association ("CCEBA"),[3] the South Carolina Coastal Conservation League ("CCL"), the Southern Alliance for Clean Energy ("SACE"), the Sierra Club, Upstate Forever, and the Natural Resources Defense Counsel ("NRDC") (together with CCL, SACE, and Sierra Club, the "Environmental Parties"), and Vote Solar, have presented

[3] On March 10, 2021, the Commission granted the South Carolina Solar Business Association's ("SCSBA") motion to be renamed in these and other dockets as CCEBA. For consistency, this Order will refer to CCEBA and *not* SCSBA regardless of the entity's name at the time of filing.

extensive evidence concerning the 2020 IRPs, as well as the reasonableness and prudence of alternatives to the 2020 IRPs presented by intervening parties. Based upon this evidence, and consistent with Act 62's new requirements, the Commission finds and concludes that the Companies' 2020 IRPs represent the most reasonable and prudent means for DEC and DEP to meet their respective energy and capacity needs for planning purposes at this time. As extensively addressed herein, the Commission further believes that its detailed analysis and plan review set forth in this Order is consistent with the intent and purpose of the General Assembly's amendments to IRP procedure in Act 62.

The Commission recognizes that 2020 IRPs are the first IRPs filed by DEC and DEP following the passage of Act 62. The work the Companies undertook to prepare thorough and sophisticated IRPs is appreciated, as well as the efforts by the Companies, ORS, and intervening parties, to thoroughly vet the 2020 IRPs through this contested case proceeding by making recommendations, presenting alternative analyses, providing additional supporting information, and further refining what will be filed in future IRP proceedings as a result of the information exchanged between the parties that have formulated the testimony, exhibits, and record of this proceeding.

The 2020 IRPs are important planning documents which will inform how the Companies should meet their public service obligations until the next IRPs are filed for the Commission's review under Act 62. As also recognized by Act 62, however, Commission approval of the IRPs for planning purposes does not pre-determine the reasonableness or prudence of DEC's or DEP's construction or acquisition of any specific resources included in the 2020 IRPs or pre-judge the reasonableness or prudence of any expenditure sought for recovery in a future rate case. S.C. Code Ann. § 58-37-40(C)(4).

A. Background on Integrated Resource Plans

Integrated resource planning is a structured, transparent process for comparing options to meet electric demand. It was introduced in the electric sector in the 1980s, has been widely adopted across the U.S., and continues to play a key role today in most states. Integrated resource planning serves a unique and vital purpose within utility regulation in that it provides a way to comprehensively and systematically consider the wide array of factors that impact electric system choices. As commonly implemented, an IRP is a long-range plan prepared by electric utilities to provide legislators, regulators, utility customers, and various other stakeholders with long-term projections of customers' anticipated capacity and energy needs and to forecast how the utility's supply-side and demand-side resources could change over the planning horizon—15 years, in the case of DEC and DEP. (Tr. Vol. 1, pp. 62.7-62.8.) When implemented prudently, the IRP process can help policy makers, regulators, and customers understand the costs and benefits of potential resource options and can illustrate the impact of various sensitivities on the long-range plans over future planning horizon.

The Legislature, in passing Act 62, significantly strengthened the IRP process in South Carolina. Compared to the previous IRP statute, Act 62 includes an expanded and more detailed list of requirements for utility IRP filings. Act 62 also enabled formal Commission review of utility plans via a litigated proceeding, in which the Commission must ultimately accept, reject, or order expedited modifications to the utility's proposed plan. Act 62 also provides for annual updates to IRPs as well as mandates new IRPs be filed routinely, at least every three years. S.C. Code Ann. § 58-37-40(A), (D). These statutory changes signal both the heightened importance the South Carolina General Assembly has assigned to IRPs and also the critical role assigned to this Commission in reviewing and ruling on proposed utility plans. (Tr. Vol. 1, pp. 62.7-62.8.) Under Act 62, the objective of an IRP is to balance resource adequacy and capacity, consumer affordability, compliance with applicable state and federal environmental regulations, power supply reliability, commodity price risks, diversity of generation supply, and other foreseeable conditions that the commission determines to be for the public interest. S.C. Code Ann. § 58-37-40(C).

B. <u>Notice and Intervention</u>

By letter dated October 29, 2020, the Clerk's Office of the Commission transmitted the Notice of Filing and Hearing and Prefile Testimony Deadlines ("Notice") in the above-referenced dockets to DEC and DEP. The Notice indicated the nature of the proceeding and advised all parties desiring participation in the scheduled proceeding of the manner and time in which to file appropriate pleadings. On December 9, 2020, the Companies filed affidavits demonstrating that the Notices were duly published in accordance with the instructions set forth in the October 29, 2020 letter.

The Companies also posted public versions of the 2020 IRPs to their respective websites in compliance with S.C. Code Ann § 58-37-40(A)(1).

Petitions to Intervene were received from CCEBA, the Environmental Parties, Vote Solar, Johnson Development Associates, Inc. ("JDA"), and Nucor Steel. The South Carolina Department of Consumer Affairs ("SCDCA") was notified of this proceeding pursuant to S.C. Code Ann. § 37-6-604(C), and submitted a petition to intervene. The Petitions to Intervene of CCEBA, CCL, SACE, Sierra Club, Upstate Forever, NRDC, JDA, Nucor Steel, and SCDCA were not opposed by the Companies, and were granted by various Orders of the Commission. No other parties sought to intervene in this proceeding. The ORS is automatically a party to this docket by virtue of S.C. Code Ann. § 58-4-10(B) (2015).

II. SUMMARY OF COMMISSION DECISION

The record before the Commission in this proceeding demonstrates that these first IRPs required to be filed under Act 62 reflect both detailed and sophisticated integrated resource planning as well as good faith efforts to incorporate stakeholder input into the 2020 IRPs.

The Companies' IRPs and supporting testimony and exhibits detail the robust analyses completed by the Companies' personnel and their experts to develop reasonable and prudent IRPs, as well as emphasize the meaningful stakeholder engagement in the areas of resource planning portfolios, carbon reduction, energy efficiency and demand side management ("EE/DSM"), as well as on the IRP development and stakeholder engagement process itself. (Tr. Vol. 1, p. 62.11.) The Commission commends the Companies for these significant efforts in developing their 2020 IRPs.

The Commission finds that the 2020 IRPs fully meet the requirements of Act 62, while taking significant steps to develop pathways to a cleaner and reliable energy future for South Carolina. The 2020 IRPs keep Duke Energy on a trajectory to meet its near-term carbon reduction goal of at least 50% as compared to 2005 levels by 2030 and long-term goal of net-zero by 2050 in the Carolinas, while exploring accelerated coal retirement options, significant increases in renewable energy resources, including solar onshore and offshore wind, and further integration and development of new technologies, among other scenarios. Notably, the Companies' six resource portfolios comprising the 2020 IRPs *all* plan for significant solar resource additions over the 15-year planning period. All six portfolios project a range of adding two to four times the current installed solar capacity by the end of the planning horizon, reflecting the Companies' commitment to the aggressive addition of solar in the Carolinas. For the first time, the IRPs contain both onshore and offshore Carolinas wind as potential resource alternatives in several of the portfolios. A common theme across the portfolios is that grid and technology improvements play an ever-important role in the Companies' road to decarbonization. The IRPs include increased energy storage, accelerated use of new technologies and provide detailed analyses on planned grid investments in both the earliest practicable and most economic coal retirements scenarios.

Act 62 tasks the Commission with assessing whether the 2020 IRPs represent the most reasonable and prudent plans for DEC and DEP, respectively, to meet their future energy and capacity needs by appropriately balancing the factors set forth in Section 58-37-40(C)(2). As further discussed in this Order, the 2020 IRPs appropriately balance these factors:

Resource Adequacy: The 2020 IRPs have robustly considered resource adequacy and plan for reliable power system operations by developing six portfolios of capacity and energy resources that provide reliable capacity to serve anticipated peak electrical load and the Companies' 17% planning reserve margins. S.C. Code Ann. § 58-37-40(C)(2)(a). The Companies engaged Astrapé Consulting ("Astrapé") to conduct comprehensive resource adequacy studies to determine the appropriate reserve margin for use in development of the Companies' 2020 IRPs. Based on results of the 2020 Resource Adequacy Studies, which included multiple case considerations and sensitivities, Astrapé recommended continued use of a 17% planning reserve margin and the Companies used this target in developing their 2020 IRPs. The Commission finds that the 2020 IRPs appropriately consider resource adequacy and are designed to achieve reliable system operations while also balancing cost impacts for customers.

Consumer Affordability: The 2020 IRPs appropriately considered the principles of consumer affordability and least cost as required by S.C. Code Ann. § 58-37-40(C)(2)(b). Two of the six portfolios included in the 2020 IRPs—the Base Case Without Carbon Policy Portfolio and the Base Case With Carbon Policy Portfolio—adhere to least cost planning criteria based upon both the current rules and statutes in place today as well as potential future regulations that may require the Companies to reach their net-zero carbon emissions goal on a more aggressive time table. The Commission finds these least cost portfolios to be reasonable for planning purposes.

Compliance with State and Federal Environmental Regulations: The 2020 IRPs appropriately reflect and take into account applicable state and federal regulations as required by S.C. Code Ann. § 58-37-40(C)(2)(c). Each of the six proposed portfolios ensure compliance with the statutes, regulations, and rules that govern the Companies' operations today. Several of the portfolios also plan for foreseeable changes to those requirements, particularly with respect to reducing carbon emission and planning for implementation of additional renewable energy resources. Importantly, ORS agreed that the Companies have appropriately planned for compliance with applicable laws and regulations in developing the 2020 IRPs.

Power Supply Reliability: Ensuring power supply reliability for South Carolina customers is critical to resource planning and the delivery of safe and reliable electric utility service. The 2020 IRPs appropriately plan for power supply reliability as required by S.C. Code Ann. § 58-37-40(C)(2)(d). As DEC/DEP witnesses pointed out throughout the hearing, the Companies have the public service obligation to plan and operate their generating fleets and transmission and distribution systems to provide reliable power system operations to their customers 24 hours per day, 7 days per week, 52 weeks per year. The Companies' 2020 IRPs take unprecedented steps to analyze and plan for integrating solar and other clean energy technologies during the 15-year planning period, as well as chart multiple paths towards Duke Energy's corporate goals of getting to net-zero emissions by 2050. To maintain system reliability during this long-term transition from a legacy fleet that included coal generation towards a new mix of cleaner generation, including renewables, battery storage systems and efficient natural gas across the Companies' systems, the

Companies' 2020 IRPs carefully address risks to ensure reliable operation of the respective systems. While many intervenors challenged the Companies' consideration and selection of new natural gas-fueled resources within the IRP portfolios, the Commission agrees with the Companies that an unbalanced and unproven resource mix resulting from biases in system planning could have critical consequences for customers. This risk is underscored by the February 2021 ERCOT event, which resulted from a complex mix of factors, including lack of effective planning, ensuring resource adequacy and resource assurance, and risk assessment and management. The plans set forth in the 2020 IRPs are appropriately targeted to ensure power supply reliability and to protect the Companies' systems from similar devastating outages.

Commodity Price Risks: The 2020 IRPs appropriately address commodity price risks as required by S.C. Code Ann. § 58-47-30(C)(2)(e). In particular, the Companies' natural gas price forecasts—which rely on market-based pricing for 10 years before transitioning to fundamental forecasts—were prepared using the same methodology that the North Carolina Utilities Commission ("NCUC") has approved for use in the Companies' IRPs over the last five years. (Tr. Vol. 6, p. 1586.66.) The ORS found this approach to be reasonable, and the Companies agreed to ORS's recommendation to engage with stakeholders regarding this methodology before their next regular IRP filing. The 2020 IRPs also presented multiple scenarios evaluating both low- and high-gas cost futures.

Diversity of Generation Supply: The 2020 IRPs appropriately plan for diversity of generation supply as required by S.C. Code Ann. § 58-47-30(C)(2)(f). Each of the Companies' six portfolios provides a broad range of scenarios evaluating a range of supply-side, demand-side and storage technologies across the scenarios. Each pathway keeps Duke Energy on a trajectory to meet its near-term carbon reduction goal of at least 50% as compared to 2005 levels by 2030 and long-term goal of net-zero by 2050 in the Carolinas, while exploring accelerated coal retirement options, significant increases in renewables, including onshore and offshore wind and further integration and development of new technologies, among other scenarios. (Tr. Vol. 1, p. 62.14.)

Planning for the Foreseeable Future: The 2020 IRPs appropriately plan for other foreseeable conditions that the Commission determines to be for the public interest. As already discussed in this Section, the 2020 IRPs plan for potential future carbon regulation that would require the Companies to reduce carbon emissions and integrate an increased amount of renewable energy to their respective systems on an accelerated timeframe.

In balancing these factors, the Commission specifically recognizes ORS's support for accepting the 2020 IRPs as reasonable for planning purposes under Act 62. The ORS has the unique role of representing the public interest by providing a balanced assessment of these statutory considerations. The ORS retained the services of Kennedy Associates to assist in its review of the 2020 IRPs. Taking each of these balancing factors under consideration, ORS and Kennedy Associates provided a robust, technically objective and holistic review of the Companies' plans, ultimately finding them to be reasonable and prudent. While ORS initially proposed a number of recommendations for the Companies to address either in this IRP proceeding or in the Companies' next comprehensive filing, it ultimately found the 2020 IRPs to be reasonable and prudent after review of additional information provided by the Companies.

In conclusion, the Commission views 2020 IRPs as a "snapshot in time" in a long-term planning process and reflective of the best available information at the time of filing. IRP development is a nearly continuous process, and as technology evolves and future statutory, regulatory and policy developments occur, these new developments will inform future IRPs. The

Companies developed the 2020 IRPs based on inputs and assumptions generally fixed in late spring and summer months of 2020 leading up to the September submittal of the IRP. By functional necessity, the analyses, cost input assumptions, and other factors represent information that was available at that point in time prior to the time of filing. While certain intervenors have recommended that the Companies be required to file a modified IRP, the Commission finds that "re-running" the IRPs and filing modified IRPs is not necessary or appropriate in this proceeding. The Companies' 2020 IRPs comply with Act 62. Moreover. the Companies plan to file an IRP update in September 2021—just three months from the date of this Order—and to submit their next comprehensive IRPs in September of 2022—just over a year from the date of this Order.

For all of the foregoing reasons, the Commission finds the 2020 IRPs to be the most reasonable and prudent means of meeting the Companies' energy and capacity needs as of the time the plan is reviewed and hereby approves the 2020 IRPs as meeting the requirements of Act 62.

III. REQUIREMENTS FOR COMMISSION REVIEW OF UTILITY INTEGRATED RESOURCE PLANNING UNDER ACT 62

As codified in S.C. Code Ann. § 58-37-40, the statutes set forth procedural and substantive requirements for utility IRP filings along with the standard of review for the Commission's review of utility IRPs.

A. Procedural Requirements

Regulated electric utilities in South Carolina must prepare and submit IRPs with the Commission at least every three years. S.C. Code Ann. § 58-37-40(A). The Commission is required to establish a proceeding to review each utility's IRP[4] in which interested parties may

[4] Section 58-37-10(2) of the South Carolina Code of Laws defines an integrated resource plan or "IRP" to mean "a plan which contains the demand and energy forecast for at least a fifteen-year period, contains the supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options, with a brief description and summary cost-benefit analysis, if available, of each option which was considered, including those not selected, sets forth the supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and describes the

intervene and conduct discovery for the purpose of "obtaining evidence concerning the [IRP], including the reasonableness and prudence of the plan and alternatives to the plan raised by intervening parties." S.C. Code Ann. § 58-37-40(C)(1).

Within 300 days of the IRP being filed, the Commission must issue a final order approving, modifying, or denying the plan. *Id.* If the Commission modifies or rejects a utility's IRP, the utility has 60 days from the date of the final order to submit a revised plan to the Commission. S.C. Code Ann. § 58-37-40(C)(3). Within 60 days after the utility makes its revised filing, ORS must review the electrical utility's revised plan and submit a report to the Commission assessing the sufficiency of the revised filing; other parties to the IRP proceeding also may submit comments. *Id.* Within 60 days after the ORS report is filed, the Commission at its discretion may determine whether to accept the revised IRP or to mandate further remedies as it deems appropriate. *Id.*

Act 62 also establishes that utilities must file annual IRP updates before the Commission. S.C. Code Ann. § 58-37-40(D).

B. Utility IRP Filing Requirements Under Act 62

S.C. Code Ann. § 58-37-40(B)(1) states that electrical utilities must include the following information in IRPs filed with the Commission under Act 62:

> (a) A long-term forecast of the utility's sales and peak demand under various reasonable scenarios;
>
> (b) The type of generation technology proposed for any generation facility contained in the plan and its proposed capacity, including fuel cost sensitivities under various reasonable scenarios;
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> (c) Projected energy purchased or produced by the utility from a renewable energy resource;
>
> (d) A summary of electrical transmission investments planned by the utility;

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external environmental and economic consequences of the plan to the extent practicable. For electrical utilities subject to the jurisdiction of the South Carolina Public Service Commission, this definition must be interpreted in a manner consistent with the integrated resource planning process adopted by the commission. . . ." S.C. Code Ann. § 58-37-10(2) (2015).

(e) Several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency (EE), and demand response (DR) measures, including consideration of:

i. customer energy efficiency and demand response programs;

ii. facility retirement assumptions; and

iii. sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks.

(f) Data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio;

(g) Plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan;

(h) An analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs; and

(i) A forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.

S.C. Code Ann. § 58-37-40(B)(1).

In addition, S.C. Code Ann. § 58-37-40(B)(2) states that IRPs may include distribution resource plans or integrated system operation plans.

C. <u>Commission Standard of Review</u>

The Commission is directed to approve a utility's IRP if it finds that "the proposed integrated resource plan represents the most *reasonable and prudent* means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." S.C. Code Ann. § 58-37-40(C)(2) (emphasis added).

To determine whether this standard was met, the Commission is directed to consider, in its discretion, whether the IRP appropriately balances the following seven factors:

> (a) Resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins;
>
> (b) Consumer affordability and least cost;
>
> (c) Compliance with applicable state and federal environmental regulations;
>
> (d) Power supply reliability;
>
> (e) Commodity price risks;
>
> (f) Diversity of generation supply; and
>
> (g) Other foreseeable conditions the Commission determines to be for the public interest.

Id.

Given the importance of this standard to its findings below, the Commission finds it necessary to further expound on this standard and the factors relevant to whether or not it is satisfied. As an initial matter, the plan must be "reasonable," meaning it is rational, logically consistent, and the result of sound judgment. In the context here, this requires consideration of whether the utility's plan meets the requirements of Act 62 and comports with industry norms and widely-known IRP best practices. *In re South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Dominion Energy South Carolina, Incorporated*, Dkt. No. 2019-226-E, Order No. 2020-832, at 12 (Dec. 23, 2020) (the "2020 DESC IRP Order"). The plan must also be "prudent," which means that it is informed by current utility operations, existing regulations and reliability requirements, and other "current" circumstances while also giving due consideration to actual and reasonably foreseeable future conditions and risks, as contemplated by Act 62. Such consideration should inform the utility's evaluation of the "the range of demand-side, supply-side, storage, and other technologies and services available" to meet the utility's obligations and take into account the relative costs and benefits of avoiding potential future risks and uncertainties, such as fuel cost, environmental regulations and the pace of retiring existing resources and adopting renewable energy and EE/DSM as part of the utility's portfolio to serve customers in the future. S.C. Code Ann. § 58-37-40(B)(1)(e)(Supp. 2019). The Commission emphasizes that although cost is an important consideration, "reasonableness" and "prudence" do not require that the utility simply select the least-cost resource plan given the inherent uncertainty of sensitivity assumptions for future conditions.

The Commission's decision must be based on the facts in the record before it; this means that the IRP and the record must provide sufficient information for the Commission to balance the seven factors identified by the General Assembly as necessary informing the reasonableness and prudence of utility IRPs. Act 62 requires that the plan must represent the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed. S.C. Code Ann. § 58-37-40(C)(2). This standard necessarily implies that each IRP should be based on reasonable and industry-accepted data and tools available to the utility, as of the date the IRP is filed. The reasonableness of IRPs obviously cannot be judged against events that had not occurred as of the date the IRP was filed with the Commission; however, the Commission also retains the right under Act 62 to take into account significant changes in circumstances occurring after the filing of an IRP that makes the data relied upon substantially inaccurate or fundamentally flawed. IRPs are updated routinely and the IRP process should not be static; rather utilities should strive to continuously improve over time as standards and practices improve and evolve. As a practical matter, changing facts and circumstances occurring after IRPs are filed (as well as Commission guidance on reasonable and appropriate inputs and assumptions) should be included in future IRP updates and/or future IRPs. Exercising the Commission's authority to require a utility to refile a backward-looking modified IRP is an extraordinary remedy that should be mandated only where modification or rejection of an IRP is necessary to immediately remedy significant deficiencies and to provide the Commission an opportunity to review an electrical utility's new plan for meeting its customers' future energy and capacity needs. *See e.g., 2020 DESC IRP Order*, at 7 (rejecting and requiring modifications to Dominion's proposed IRP due to "significant deficiencies" in the plan).

Consistent with the purposes of Act 62, the integrated resource planning provisions of Act 62 include requirements intended to identify and mitigate potential risks to ratepayers. IRPs must include multiple resource portfolios and "sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks." S.C. Code Ann. § 58-37-40(B)(1)(e)(iii). For these various sensitivity analyses, the Act also specifies the required use of "reasonable scenarios." S.C. Code Ann. § 58-37-40(B)(1)(b). These requirements assure that utilities in South Carolina are planning for a reasonable range of future operating conditions and market circumstances to ensure South Carolinas customers continue to receive reliable and affordable electric service.

Finally, it is important to emphasize that Commission approval of the IRPs for planning purposes does not pre-determine the reasonableness or prudence of DEC's or DEP's construction or acquisition of any specific resources included in the IRPs or pre-judge the reasonableness or prudence of any expenditure sought for recovery in a future rate case. S.C. Code Ann. § 58-37-40(C)(4). As further discussed in this Order, the IRPs are a snapshot in time to be used for planning purposes and will continue to be reviewed and refined over time. The Commission reviews and approves the Companies' selection of new generating resources and recovery of costs of providing utility service in South Carolina under other sections of Title 58 and the new IRP Statute does not change these standards and requirements.

IV. HEARING

To consider the merits of this case, the Commission convened an evidentiary hearing on this matter that took place from April 26, 2021 to May 5, 2021, with the Honorable Justin T. Williams presiding. The Companies were represented by Heather Shirley Smith, Esq.; Rebecca J. Dulin, Esq.; Samuel J. Wellborn, Esq.; Frank R. Ellerbe, Esq.; and E. Brett Breitschwerdt, Esq.. CCEBA was represented by Richard L. Whitt, Esq.; Benjamin L. Snowden, Esq.; and John D. Burns, Esq. The Environmental Parties were represented by Katherine Lee Mixon, Esq. and Gudrun E. Thompson, Esq. Vote Solar was represented by R. Taylor Speer, Esq. JDA was represented by Weston Adams, III, Esq. and Courtney E. Walsh, Esq. Andrew M. Bateman, Esq. and Jeffrey M. Nelson, Esq. represented ORS. In this Order, ORS, CCEBA, the Environmental Parties, Vote Solar, JDA, DEC, and DEP are collectively referred to as the "Parties" or sometimes individually as a "Party."

The Companies presented the direct testimonies and exhibits of Glen A. Snider, Dewey S. "Sammy" Roberts, II, Dawn A. Santoianni, Brian Bak, Leon Brunson, Matthew Kalemba, and Nick Wintermantel. CCEBA presented the direct testimonies and exhibits of Arne Olson and Kevin Lucas. The Environmental Parties presented the direct testimonies and exhibits of James F. Wilson and Jim Grevatt. Vote Solar presented the direct testimony and exhibits of Tyler J. Fitch. The ORS presented the direct testimonies and exhibits of Anthony M. Sandonato, Philip Hayet, Stephen J. Baron, and Lane Kollen.

In response to the direct testimony filed by ORS, CCEBA, the Environmental Parties, and Vote Solar, the Companies presented the rebuttal testimony and exhibits of Jim Herndon, Dewey S. "Sammy" Roberts, II, Brian Bak, Leon Brunson, Matthew Kalemba, Dawn A. Santoianni, Mark Oliver, Nick Wintermantel, and Glen A. Snider. CCEBA then presented the surrebuttal testimonies and exhibits of Arne Olson and Kevin Lucas. The Environmental Parties presented the surrebuttal testimonies and exhibits of James F. Wilson, John D. Wilson, and Jim Grevatt. CCEBA and the Environmental Parties (together, the "Clean Energy Intervenors") jointly presented the surrebuttal testimony and exhibits of Rachel Wilson. Vote Solar presented the surrebuttal and exhibits of Tyler J. Fitch. The ORS presented the surrebuttal testimonies and exhibits of Anthony M. Sandonato, Philip Hayet, Stephen J. Baron, and Lane Kollen.

V. FINDINGS OF FACT

Based on the DEC and DEP 2020 IRPs, the testimony, and the exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission hereby makes the following findings of fact:

A. DEC and DEP 2020 IRPs Meet or Exceed Section 40(B) Filing Requirements

1. The six portfolios that make up the Companies' 2020 IRPs meet or exceed each of the Section 40(B)(1) filing requirements.

2. The 15-year long-term resource planning period (2021-2035) analyzed in the 2020 IRPs is reasonable for planning purposes and compliant with Act 62.

3. The Companies' inclusion of integrated system operations planning studies and analyses is reasonable and appropriate under Section 40(B)(2) and assists the Commission in its assessment of DEC's and DEP's future system operations to reliably serve customers' electricity needs in South Carolina.

4. Act 62 requires the Companies to file comprehensive IRPs with the Commission at least every three years, and to file annual updates between IRPs. The Commission recognizes and accepts the Companies' commitments to file their next comprehensive IRPs in September 2022.

B. Alternative IRP Proposals and Intervenor Recommendations and Critiques of 2020 IRPs

1. Alternative IRP – Synapse Report

5. The "illustrative" resource plan presented in the Synapse Report sponsored by the Clean Energy Intervenors is not appropriate for consideration in this proceeding as it presented new matters filed through surrebuttal in contravention of the Commission's procedural order and in violation of Act 62's clear directive to allow an opportunity for the Companies to conduct discovery on alternative IRPs and for ORS to review and opine on the analysis. It is reasonable for the Commission to strike the Synapse Report from the record.

2. Intervenor Recommendations to Modify 2020 IRPs

a. *Load Forecast and Resource Adequacy*

6. The Companies' customer load growth and peak demand forecasting studies and scenarios are reasonable.

7. The Companies' Resource Adequacy Studies and applicable 17% planning reserve margins are reasonable to serve the Companies' anticipated peak electrical load, and meet the requirements of Act 62. Intervenor challenges to the Resource Adequacy Studies and planning reserve margins are rejected, as they are not more reasonable or appropriate than the Companies' plans to ensure that the Companies can reliably meet DEC's and DEP's future energy and capacity needs.

b. *Natural Gas Price Forecasts*

8. The Companies' natural gas price forecasting methodology is reasonable, meets the requirements of Act 62 to evaluate multiple fuel sensitivity analyses, and is consistent with the Commission-approved avoided cost methodology recently approved under Act 62, as well as the methodology DEC and DEP have consistently used for IRPs in both North Carolina and South

Carolina. Intervenor challenges to the Companies' natural gas price forecasting methodology are rejected, as the alternative recommendations would increase commodity price risks for consumers and are not more reasonable than the Companies' plans.

9. It is reasonable for the Companies to engage with ORS and other stakeholders to review their natural gas price forecasting methodology before filing their next comprehensive IRPs.

c. *Coal Retirement*

10. The Companies' detailed analysis of both the most economic and earliest practicable retirement options for DEC's and DEP's operating coal generation are reasonable for planning purposes and exceed the requirements of Act 62 to provide data regarding the utility's current generation portfolio in IRPs. The Companies' Base Plan portfolios reasonably plan for the most economic approach to coal retirements, and the Companies should continue to analyze the cost and reliability impacts of planning for earlier retirement of DEC's and DEP's operating coal generation plants as part of their ongoing resource planning assessment should emerging environmental policy or changing market conditions negatively alter the economic viability of the Companies' coal units relative to the analyses presented in this proceeding.

11. The Clean Energy Intervenors' critique of the Companies' coal retirement analysis by Clean Energy Intervenors' Witness Rachel Wilson is not appropriate for consideration in this proceeding as it presents new matters that were filed in contravention of the Commission's procedural order and in violation of Act 62's clear directive to allow an opportunity for the Companies to conduct discovery and for ORS to review the analysis. Accordingly, after renewed consideration of this issue, the Commission strikes Witness Wilson's testimony and the Synapse Report from the record.

d. *Planning for New Natural Gas Capacity*

12. The Companies' assessment and inclusion of new natural gas generation technology capacity additions as part of the 2020 IRP portfolios is reasonable and promotes a number of factors the Commission must balance under Act 62, including ensuring resource adequacy and power supply reliability, maintaining a diverse generation supply, and consumer affordability and least cost planning. No evidence was presented that planning for new natural gas generation would be non-compliant with applicable state or federal environmental regulations. It is reasonable for the Commission to reject Vote Solar's challenges to the Companies' natural gas capacity planning as its alternative recommendations are based on flawed analyses and do not appropriately consider power supply reliability risk.

13. The Intervenors' advocacy for retiring the Companies' coal-fired power plants and not adding new natural gas technology would introduce significant uncertainties and risks as DEC and DEP must ensure power supply reliability and customer affordability while also planning to add significant new solar and storage as part of a diverse resource portfolio. The Commission recognizes the critical importance of maintaining compliance with NERC reliability standards and ensuring dispatchable generating capacity is available to meet the utility's service obligations in the future.

e. *Solar, Wind, and Battery Storage Cost and Modeling Assumptions*

14. The Companies' modeling of solar generation technology is reasonable and meets the requirements of Act 62 to evaluate low, medium, and high cases for the adoption of renewable energy. Intervenor CCEBA's alternative recommendations to modify the Companies' modeling are not more reasonable or appropriate than the Companies' inputs, assumptions and modeling.

15. Resource planning scenarios under Act 62 must ensure that proposed new generating technology capacity additions can be achieved, as planned, in order to ensure resource

adequacy is maintained and that the utility can meet its service obligations to reliably serve customers' future energy and capacity needs. The Companies' 500 MW limitation on the amount of new solar that can be interconnected each year is reasonable for planning purposes and fully aligns with DEC's and DEP's historic experience interconnecting new solar generation to their systems.

16. The Companies appropriately recognize that potential changes in solar generation technology costs and operational capabilities should be factored into future IRPs. Changes to federal law enacted in December 2020 to extend the solar investment tax credit should be factored into the 2021 IRP update.

17. It is reasonable for the Companies to include a solar purchase power agreement ("PPA") resource option as a sensitivity to the two base cases in the 2021 IRP Update.

18. The 2020 IRP portfolios fairly evaluate and plan for battery storage technology to meet the utility's service obligations as required by Section 58-47-30(B(1)(e) of Act 62. The Companies' cost assumptions for battery storage are reasonable for purposes of the 2020 IRPs but should continue to be refined in the future.

19. The Companies' use of a sequential, rather than single step, approach to modeling optimization of battery storage with solar is reasonable, prudent, and appropriately accounts for the synergies with solar. It is reasonable for the Commission to reject intervenor challenges to the Companies' modeling as the alternative recommendations would not meaningfully impact the Companies' plan.

f. *Current and Foreseeable Environmental Regulations*

20. The Companies' 2020 IRPs appropriately recognize and plan for environmental regulations that exist today as well as analyze foreseeable potential regulations on carbon emissions that could impact the Companies' operations in the future. This approach is reasonable

and meets the requirements of Act 62. Intervenor challenges based on climate change risk are not based upon compliance with applicable state and federal environmental regulations that exist today, and these parties' alternative assessments of potential foreseeable conditions are not more reasonable or appropriate than the Companies' plans. A singular focus on climate change risk based upon potential future regulatory requirements does not reasonably balance the requirements of Act 62 including power system reliability and affordability for customers.

g. *EE/DSM*

21. The Companies' evaluations of the adoption of EE/DSM or demand response measures and programs are reasonable and meet the requirements of Act 62. The Companies' evidence demonstrated that the Market Potential Studies upon which its EE/DSM evaluations were based are accurate, robust, and comprehensive. In contrast to suggestions by the Environmental Parties, the Companies' inputs and methodology were evidence-based and specific to DEC's and DEP's systems, geographic territories, and customers, thereby ensuring that the modeling was reliable and appropriate for use in resource planning. The Companies' 2020 IRPs reasonably plan for EE/DSM that is cost-effective, reasonable, and achievable.

22. The Environmental Parties' recommendation that the Companies assume savings resulting from unnamed "emerging technologies" in evaluating EE/DSM potential is not reasonable and would introduce reliability risk with no attendant benefit. Likewise, while the Environmental Parties proposed that the Companies assume and "be directed" to achieve EE/DSM savings rates of up to 2% of retails sales, we find that such proposal would be inappropriate in this IRP proceeding as it does not square with the purpose of reliable and cost-effective system planning. Further, the Companies have already committed to proposing any EE/DSM measure that is cost-effective for customers.

3. Other Considerations Beyond the Scope of IRP Proceedings Under Act 62

a. *Fundamental Market Reforms*

23. Wholesale power market constructs and transactions, such as the Southeast Energy Exchange Market ("SEEM") are regulated by FERC. However, to the extent SEEM is approved by FERC and impacts IRP, it is reasonable for the Companies to provide, in future comprehensive IRPs, details regarding the status of SEEM, and information regarding the benefits of participation in SEEM, as recommended by ORS.

24. CCEBA's and Vote Solar's recommendation for the Companies to study the costs of and to plan for operating within an Energy Imbalance Market ("EIM") or Regional Transmission Organization ("RTO") market structure are not appropriate for consideration in this IRP proceeding. Such fundamental market reforms require legislative action and are beyond the scope of integrated resource planning under Ac 62.

b. *IRP Modeling and Transparency for Future IRPs*

25. The Companies' capacity expansion and production cost modeling approach in the 2020 IRPs was reasonable. For the 2021 IRP update and 2022 comprehensive IRPs, the Companies are planning to transition to the use of Encompass to model capacity expansion and production cost. The Companies' plans to transition to Encompass were not subject to any of the criticisms targeted at DESC's PLEXOS modeling software. Vote Solar's recommendation that the Companies should procure software licenses for intervenors is not reasonable and is hereby rejected.

c. *All-Source Procurement*

26. All-Source Procurement Report sponsored by Environmental Parties witness John Wilson is not appropriate for consideration in this proceeding as it presented new matters filed in

contravention of the Commission's procedural order and in violation of Act 62's clear directive to allow an opportunity for the Companies to conduct discovery on alternative IRPs and for the ORS to review and opine on the analysis. It is reasonable for the Commission to strike the All-Source Procurement Report from the record.

C. Approval of 2020 IRPs as Most Reasonable and Prudent Plans

27. The six portfolios that make up the Companies' 2020 IRPs are thorough, sophisticated, and meet or exceed the requirements of Act 62 set forth in S.C. Code Ann. § 58-27-40 by forecasting for a variety of potential future scenarios, including two base cases which plan for futures both with and without carbon regulation. The Commission finds no deficiencies in the detailed studies, reports, and analyses developed by DEC and DEP to comply with Act 62's requirements requiring the Companies to file modified IRPs.

28. The ORS supports approval of the Companies' 2020 IRPs without modification prior to the Companies' next IRP update or comprehensive IRP on the grounds that the 2020 IRPs are sophisticated, reasonable, and prudent and recognize the Companies' commitment to address certain ORS recommendations in future IRP proceedings.

29. The six portfolios that make up the Companies' 2020 IRPs appropriately balance resource adequacy and capacity to serve anticipated peak electrical load and applicable planning reserve margins; consumer affordability and least cost; compliance with applicable state and federal environmental regulations; power supply reliability; commodity price risks; diversity of generation supply, and other foreseeable conditions that the Commission determines to be for the public interest.

30. It is reasonable for the Commission to approve the Companies' 2020 IRPs as total IRPs that present the most reasonable and prudent plan to meet the Companies' capacity and energy needs, as required by Act 62. Plan A Base Case Without Carbon Policy reflects the

Companies' least cost plan that reflects compliance with the legal and regulatory requirements in effect today and is the Companies' "appropriate plan" for use in other proceedings, such as avoided cost and DSM/EE cost effectiveness.

31. The Companies' Short Term Action Plans are reasonable for planning purposes at this time.

VI. EVIDENCE AND CONCLUSIONS

A. <u>DEC and DEP 2020 IRPs Meet or Exceed Section 40(B) Filing Requirements</u>

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 1-4

<u>Evidence in Support</u>

The evidence supporting these findings of fact and conclusions is contained in the Companies' 2020 IRPs, testimony, and exhibits in these Dockets, and the entire record in this proceeding.

<u>Overview of 2020 IRPs</u>

DEC/DEP Witness Snider presented the Companies' 2020 IRPs and explained that they were prepared to conform with the requirements of S.C. Code Ann. § 58-37-40 and meet all statutory requirements for approval by the Commission. (Tr. Vol. 1, p. 62.8; H. Ex. 1.) DEC and DEP operate as individual utility systems with service territories across South Carolina and North Carolina and, accordingly, have prepared similar, but separate IRPs for each system. (Tr. Vol. 1, p. 62.9.) According to Witness Snider, the 2020 IRPs are the product of nearly a year's worth of work and tremendous amounts of time from internal subject matter experts across the Companies' organization as well as national experts hired to support the various studies that informed the IRP and are included as Attachments to each Companies' IRP filing. (Tr. Vol. 6, p. 1586.39.) In addition, the Companies utilized sophisticated modeling and analysis performed by individuals spanning multiple functional disciplines who collectively represent hundreds of years of industry experience. (*Id.*)

The Companies' 2020 IRPs each contain six different resource portfolios that make up a single integrated resource plan as contemplated in Act 62, each of which includes numerous individual sensitivities to input variables. (*Id.*) The six resource portfolios contain two base portfolios: first, a "Base without Carbon Policy" portfolio that plans for current environmental regulation and does not assume future regulations on carbon dioxide; and second, a "Base with Carbon Policy" that assumes future regulations on carbon dioxide emissions. (*Id.*) The Base Case without Carbon Policy presents a portfolio that adheres to lowest cost planning criteria achievable under the currently applicable rules, statutes, and regulations—that is, without any legally binding carbon reduction mandate. (Tr. Vol. 1, p. 62.15.) Under this portfolio, the Companies' optimization modeling largely selects new natural gas generation to replace retiring coal capacity and meet future load growth, while still increasing solar capacity by 4 GW across both systems throughout the 15-year planning period. (*Id.*) Even without additional incentive from state or federal energy policy, this portfolio achieves a 56% reduction in carbon emissions through 2030 with a Present Value Revenue Requirement ("PVRR") through 2050 of $79.8 billion. (*Id.*) The Base Case without Carbon Policy is more fully discussed in Appendix A of each Company's IRP (H. Ex. 1, DEC 2020 IRP, p. 162; DEP 2020 IRP, p. 162.)

In contrast, the Companies' Base Case with Carbon Policy presents a portfolio that adheres to least cost planning while assuming a future regulatory requirement to reduce carbon emissions. (Tr. Vol. 1, p. 62.16.) Under this portfolio, the Companies' optimization modeling selects an increased amount of renewable resources as compared to the Base Case without Carbon Policy, including 8 GW of new solar along with 750 MW of onshore wind. (*Id.*) Notwithstanding the increased renewable selection, this portfolio still replaces much of the Companies' retiring coal capacity with new natural gas generation. Ultimately, the portfolio achieves a 59% reduction in carbon emissions through 2030 and has a PVRR through 2050 of $82.5 billion. (*Id.*)

Beyond these two base cases, the four remaining portfolios achieve more aggressive carbon reduction goals than the two bases, exploring a variety of potential options through portfolios that prioritize: (1) earliest practicable retirement of coal generating facilities; (2) aggressive carbon reduction through wind resources; (3) aggressive carbon reduction through small modular nuclear resources; and (4) implementing no new natural gas generation. (Tr. Vol. 1, pp. 62.9, 62.14, 62.17-62.21.) Importantly, DEC/DEP Witness Snider explained that all six of the portfolios balance resource adequacy and power supply reliability, customer affordability, regulatory compliance, commodity price risk, and plan for diversity of both supply-side and demand-side resources, and they each set the Companies on track to reach the Duke Energy corporate goal set to reduce carbon emissions by 50% (as compared to 2005 levels) by 2030 and to reach net-zero carbon emissions by 2050. (Tr. Vol. 1, p. 62.14; Tr. Vol. 6, p. 1586.5.) As Witness Snider explained, the six portfolios and range of scenarios presented by the Companies provides stakeholders, customers, legislators, and regulators with insight into varying possible pathways for DEC and DEP to meet their respective service obligations as future industry policies and technologies evolve in real time. (Tr. Vol. 1, p. 62.14.)

As Witness Snider explained, resource planning assumptions change constantly as rapidly advancing technology and new laws and regulations impact the long-term costs and benefits of the Companies' plan. (Tr. Vol. 6, p. 1586.42.) In addition, the Companies are in the midst of an unprecedented, long-term transition from a legacy fleet that included significant coal-fired generation towards a new mix of cleaner generation technologies, including renewables, battery storage systems, and efficient natural gas across the Companies' systems. (Tr. Vol. 6, p. 1586.7.) For all of these reasons, Witness Snider urged the Commission to consider the 2020 IRPs as a "snapshot in time"—*i.e.*, that they are reflective of the best available information at the time of filing, using inputs and assumptions from the spring and summer months of 2020, leading up to the September 1, 2020 IRP filings. (Tr. Vol. 6, p. 1586.43.) Witness Snider noted that the IRP process is nearly continuous, highlighting that the Companies will submit an update to their 2020 IRPs in September 2021 and plan to file their next comprehensive IRP in September 2022, an entire year before they are required to do so by Act 62. (Tr. Vol. 6, pp. 1586.46-47.) Overall, Witness Snider underscored that the Companies' 2020 IRPs are the product of a sophisticated, considered approach to prudently and judiciously plan for and execute this transition in a way that protects system reliability and customer affordability. (*Id.*)

Act 62 IRP Filing Requirements

Section 58-27-40(B)(1) requires utilities to address a list of eight considerations in their IRPs. DEC/DEP's Witnesses described how the Companies' 2020 IRPs addressed each requirement.

First, Section 58-27-40(B)(1)(a) requires utilities to include "a long-term forecast of the utility's sales and peak demand under various reasonable scenarios." Witness Brunson explained that the 2020 IRPs project the energy and peak demand needs for their respective service areas using the Companies' Spring 2020 load forecast. (Tr. Vol. 2, pp. 293-95.) While this load forecast represents the expectations of customers' needs under expected circumstances, the Companies also modeled the impacts, both high and low, of potential fluctuations to the load forecast on each portfolio. (Tr. Vol. 1, p. 62.26.) Details of the load forecast are included in Chapter 3 and Appendix C of the 2020 IRPs.

Section 58-27-40(B)(1)(b) requires utilities to describe the "type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including fuel cost sensitivities under various reasonable scenarios." Witness Snider explained that Appendix A to the 2020 IRPs provides the type of generation technologies and capacity proposed for each generation facility contained in the six portfolios. Tables A-7, A-10, A-12, and Figures A-4 through A-9 address fuel cost sensitivities by showing how resource selection may shift based on fuel price, load, and resource cost sensitivities. Witness Snider explained that Appendix A also discusses results of each selection based on economics or to illustrate the desired outcome of the portfolio. (Tr. Vol. 1, p. 62.27.)

Section 58-27-40(B)(1)(c) requires utilities to state the "projected energy purchased or produced by the utility from a renewable energy source." Witness Kalemba described the range of renewable resources included in each of the six portfolios. (Tr. Vol. 2, p. 325.9-13.)

Section 58-27-40(B)(1)(d) requires utilities to provide a "summary of the electrical transmission investments planned by the utility." Witness Roberts provided extensive detail regarding the transmission investments planned by DEC and DEP, as well as cost estimates for the transmission investment needed to implement each of the six resource portfolios contained in the IRPs. Chapters 7 and 11 and Appendices A and L of the IRPs also directly address these investments. (H. Ex. 1, DEC 2020 IRP, pp. 53-60, 77-85; DEP 2020 IRP pp. 55-62, 79-88.)

Section 58-27-40(B)(1)(e) requires utilities to include "several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other other technologies and services available to meet the utility's service obligations." In doing so, the Section directs utilities to evaluate "low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures[.]" S.C.

Code Ann. § 58-27-40(B)(1)(e). Witness Snider explained that the six resource portfolios included in the 2020 IRPs meet this requirement by providing a range of technology options by which to meet the utility's service obligations under various possible sensitivities and scenarios as required by Section 58-27-40(B)(1)(e)(iii). (Tr. Vol. 1, p. 62.29.) As Witness Snider explained, the 2020 IRPs contain extensive analysis and discussion of the various portfolios, sensitivities and scenario analysis conducted in order to evaluate the range of supply-side, demand-side, storage, and other technologies as outlined in Act 62. (*Id.*) In addition, the Companies developed low, medium, and high cases for the adoption of renewable energy, energy efficiency, and demand response, which were evaluated in the sensitivity analysis to inform the development of the alternative portfolios presented in the IRPs. (Tr. Vol. 1, p. 62.28.)

Section 58-27-40(B)(1)(e)(i) requires utilities to consider "customer energy efficiency and demand response programs." Witness Bak explained that the 2020 IRPs contain an entire chapter and an appendix on Energy Efficiency and Demand Response programs (Chapter 4 and Appendix D, respectively). (H. Ex. 1, DEC 2020 IRP, pp. 34-37, 244-84; DEP 2020 IRP, pp. 34-37, 235-77.) The IRPs also detail a variety of demand-response programs that signal customers to reduce electricity use during select peak hours as specified by the Companies and treats these "dispatchable" types of programs as resource options that can be dispatched to meet system capacity needs during periods of peak demand. (H. Ex. 1, DEC 2020 IRP, p. 35; DEP 2020 IRP, p. 35.) Finally, the Companies commissioned an EE Market Potential Study ("MPS") to obtain estimates of the technical, economic and achievable potential for EE savings under three distinct portfolios—a base portfolio, an enhanced portfolio, and a low portfolio. (H. Ex. 1, DEC 2020 IRP, pp. 35-36; DEP 2020 IRP, pp. 35-36.)

Section 58-27-40(B)(1)(e)(ii) requires utilities to consider "facility retirement assumptions." To address this requirement, the Companies are planning for the potential retirement of some of their older, less efficient generation resources. (H. Ex. 1, DEC 2020 IRP, p. 7; DEP 2020 IRP, p. 7.) In particular, while the Companies' coal assets continue to provide year-round energy that is especially critical during winter and summer peaks, the Companies conducted a detailed coal plant retirement analysis to determine the most economic retirement dates for each of the Company's coal assets. (H. Ex. 1, DEC 2020 IRP, p. 77; H. Ex. 1, DEP 2020 IRP, p. 77.) This analysis identified the retirement dates used in the two Base Cases developed with and without carbon policy for each of DEC's and DEP's coal plants. (*Id.*) In addition to the economic retirement analysis, the Companies also determined the earliest practicable retirement dates for each coal asset. (*Id.*)

Section 58-27-40(B)(1)(f) requires utilities to provide "data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio." Witness Snider explained that Appendix B of the 2020 IRPs contains a detailed summary of the Companies' current generation portfolio. (Tr. Vol. 1, p. 62.32.) Information is provided for each unit regarding the unit's winter and summer capacity rating, fuel type, current age, estimated remaining life and licensing status, where applicable. (Tr. Vol. 1, p. 62.33.)

Section 58-27-40(B)(1)(g) requires utilities to provide "plans for meeting current and future capacity needs with the cost estimates for all proposed resource portfolios in the plan." Witness Snider explained that each of the six portfolios included in the 2020 IRPs meet current and future capacity needs and provide the associated cost estimates for all proposed resources in the portfolio. (Tr. Vol. 1, p. 62.35.) Cost estimates for the six portfolios in each of the nine gas price and carbon tax scenarios are provided in Appendix A, Tables A-15 and A-16 of the 2020 IRPs and sensitivities are presented in Table A-9. (H. Ex. 1, DEC 2020 IRP, p. 169; DEP 2020 IRP, p. 168.)

Section 58-27-40(B)(1)(h) requires utilities to provide "an analysis of the cost and reliability impacts of all reasonable options available to meet projected energy and capacity needs." Witness Snider explained that the 2020 IRPs contain extensive analysis on the potential cost and reliability impacts of each of the portfolios presented. (Tr. Vol. 1, pp. 62.35-36.) In addition to analyzing the PVRR, which assesses the total operating cost of the system along with incremental capital and operating costs of new resources shown on a present value basis, the Companies presented a residential average bill impact for each portfolio in Appendix A. This additional metric provides stakeholders with a more relatable measure of the cost tradeoffs between the portfolios. (Tr. Vol. 1, p. 62.36.) Planning for ensuring power system reliability is discussed throughout the IRP, with significant detail provided in Chapters 6 and 9 and Appendices A and H as well as in the Companies' Resource Adequacy Study (Attachment III) and Storage Effective Load Carrying Study (Attachment IV).

Finally, Section 58-27-40(B)(1)(i) requires utilities to provide "a forecast of the utility's peak demand, details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction." Witness Brunson explained that the 2020 IRPs contain load forecasts for annual energy growth over the planning horizon, as well as winter peak demand and summer peak demand growth for the same period. (Tr. Vol. 1, p. 258.5; Tr. Vol. 2, pp. 293-94.)

In addition to addressing each of the requirements in Section 58-27-40(B)(1) and conducting significant, in-depth analyses to inform and support the Companies' approach to each resource planning area required by Act 62, Witness Snider explained that the 2020 IRPs included several additional areas of focus that were not expressly mandated by Act 62. (Tr. Vol. 6, p. 1586.29.) Examples of the Companies going above and beyond the requirements of Act 62 include (1) preparing a residential average bill impact analysis for each portfolio in order to provide stakeholders with a more relatable measure of the cost tradeoffs between the portfolios; (2) commissioning the MPS study; (3) commissioning an energy storage effective load carrying capability ("ELCC") study; and (4) conducting an economic coal retirement study and earliest practicable retirement study. (Tr. Vol. 6, pp. 1586.29-30.)

The Companies also undertook significant efforts to engage stakeholders in both South Carolina and North Carolina to inform their 2020 IRPs, including by: (1) holding multiple professionally-facilitated stakeholders meetings prior to and after the filing of the 2020 IRPs to explain results; (2) creating an IRP engagement website; and (3) developing a first-of-its-kind utility-supported, interactive and web enabled "Portfolio Screening Tool" accessible at https://screeningtool.duke-energy.com that allows stakeholders to test a portfolio over a 7-day winter, spring, or summer period in DEC and DEP's service territory. (Tr. Vol. 6, p. 1586.34.) The Companies' stakeholder engagement process took place over a six-month period, and participants reflected a wide range of interests, including ORS, the North Carolina Public Staff, business customers, consumer advocates, environmental advocates, solar developers, and many of the intervenors to this proceeding. (Tr. Vol. 1, p. 62.10.) Ultimately, stakeholders provided recommendations in the areas of resource planning, carbon reduction, energy efficiency, and demand response, as well as feedback on the IRP development and stakeholder engagement processes. (Tr. Vol. 1, p. 62.11; H. Ex. 1, DEC 2020 IRP pp. 46-73.) The Companies incorporated this feedback in a number of ways, including by preparing some of the more aggressive carbon reduction portfolios included in the 2020 IRPs. (Tr. Vol. 1, p. 62.13.) The ORS was supportive of the Companies' stakeholder engagement efforts, and Witness Hayet—who participated in the stakeholder process on behalf of ORS—affirmed that the stakeholder engagement was a "constructive process that should be continued" as a result of the Companies' "significant efforts[.]" (Tr. Vol. 3, p. 868.)

<u>*ORS Position*</u>

To evaluate the Companies' IRPs, ORS Witness Sandonato explained that ORS retained the services of Kennedy Associates, an economic consulting firm specializing in the electric, natural gas, and water industries with extensive collective experience evaluating IRPs across the country. (Tr. Vol. 3, p. 814.) ORS Witnesses Baron, Hayet, and Kollen, each of Kennedy Associates, analyzed the Companies' respective 2020 IRPs in the context of the criteria set forth in S.C. Code Ann. § 58-37-40(B)(1). The ORS Reports review each requirement specified by Act 62 and address in detail how DEC's and DEP's respective 2020 IRPs comply with each section specified by the General Assembly in Act 62. (*Id.*)

Upon review of the Companies' 2020 IRPs and direct testimony, ORS "concluded that the Companies complied with the informational requirements identified in Section 40(B)(1)[,]". (Tr. Vol. 3, p. 851.) The ORS Report describes in detail the Companies' compliance with each of the informational requirements. (H. Ex. 24, p. 16-21; H. Ex. 25, p. 16-21.)

<u>Commission Conclusions</u>

The Commission finds that the Companies' 2020 IRPs meet and, in many ways, exceed the filing requirements of Act 62. The 2020 IRPs robustly address each of the nine discrete elements that must be included in an electrical utility's IRP pursuant to S.C. Code Ann. § 58-37-40(B)(1) by providing thorough, reasoned analyses prepared by the Companies' internal and external subject matter experts. The ORS agrees that the Companies have complied with, and often exceeded these filing requirements. Moreover, the six resource portfolios that make up the 2020 IRPs offer a broad range of scenarios that will allow the Companies and the Commission flexibility to plan for evolving technologies, increases or decreases in operating and capital costs of various generation technologies or commodity costs, as well as changing laws and regulations. These multiple portfolios satisfy the mandate in S.C. Code Ann. § 58-37-40(B)(e) to develop "several resource portfolios" that "fairly evaluat[e] the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations." For all of the foregoing reasons, the Commission finds that the Companies' 2020 IRPs comply with the filing requirements of Act 62.

B. Alternative IRP Proposal and Intervenor Recommendations to Modify 2020 IRPs

1. Alternative IRP – Synapse Report

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 5

Evidence in Support

The evidence in support of this finding of fact is found in the Companies' 2020 IRPs, pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

CCEBA and the Environmental Parties submitted an alternative resource plan that was presented as an Exhibit to Witness Rachel Wilson's surrebuttal testimony entitled *Clean, Affordable, and Reliable: A Plan for Duke Energy's Future in the Carolinas* (the "Synapse Alternative Plan"). This 22-page Synapse Alternative Plan was authored by Witness Wilson and several colleagues from Synapse Energy Economics, Inc. ("Synapse"). (H. Ex. 56, Synapse Report.)

The Companies moved to strike the Synapse Alternative Plan on April 19, 2021—two business days after it was filed in this docket—on the grounds that it was improper for the Clean

Energy Intervenors to file an alternative IRP in surrebuttal testimony under the procedural requirements of Section 58-27-40(C)(2) as well as prevailing case law and Commission practice. Specifically, the Companies argued that surrebuttal is intended for the limited purpose of responding to issues raised by an opposing party in rebuttal testimony, and it is improper to raise new matters for the first time in surrebuttal testimony. Similarly, the Companies argued that Act 62 requires the Commission to allow fulsome discovery on all "alternative plans," and there was no opportunity to do so or otherwise vet the Synapse Alternative Plan in the 12 intervening days between its filing and hearing commencement. In response, CCEBA and the Environmental Parties argued that (1) the Commission has broad discretion to hear relevant evidence; (2) the Synapse Alternative Plan is within the proper scope of surrebuttal as it responds to the rebuttal testimony of DEC/DEP Witness Snider; and (3) the Companies were not prejudiced by the late date of filing because several of the Environmental Parties filed the Synapse Alternative Plan on March 22, 2021, in the IRP proceeding before the North Carolina Utilities Commission, Docket No. E-100, Sub 165. The Commission denied the motion in a bench ruling, but granted the Companies leave to refile at the close of the hearing. Witnesses Roberts and Bak both testified that, because the report was filed shortly before the hearing, they had not had an opportunity to thoroughly review or perform a detailed evaluation of the report or Ms. Wilson's testimony, or the assumptions relied upon by them. (Tr. Vol. 4, pp. 1053-54, 1214-1215.) The Companies renewed their Motion to Strike on June 9, 2021, based on the same underlying arguments. The Motion is now ripe for the Commission's consideration.

<u>Commission Conclusions</u>

Considering the Companies' renewed Motion to Strike, the Commission finds that it was improper for CCEBA and the Environmental Parties to file the Synapse Alternative Plan as an

Exhibit to surrebuttal testimony in this proceeding. As a threshold matter, surrebuttal testimony before this Commission is discretionary and proper for the limited purpose of replying to new matters raised in rebuttal testimony. *See State v. Watson*, 353 S.C. 620, 623-24, 579 S.E.2d 148, 150 (Ct. App. 2003) ("Surrebuttal is appropriate when, in the judge's discretion, new matter or new facts are injected for the first time in rebuttal"); *U.S. v. Barnette*, 211 F.3d 803, 821 (4th Cir. 2000) ("Surrebuttal evidence is admissible to respond to any *new matter* brought up on rebuttal.") (emphasis added); *State v. Farrow*, 332 S.C. 190, 194 (S.C. App., 1998) ("We thus hold the reply testimony . . . was improper because it was not presented to rebut evidence adduced by Farrow.") (citing *Daniel v. Tower Trucking Co.*, 205 S.C. 333, 32 S.E.2d 5 (1944)).

The policy reason underlying the long-standing requirement that surrebuttal testimony only be offered in response to new matters raised in rebuttal testimony is that it would be fundamentally unfair for a party to raise an issue for the first time in surrebuttal testimony without the party with the burden of proof (in this proceeding, the Companies) being given a corresponding opportunity to introduce responsive evidence. The lack of an opportunity to introduce responsive evidence to this new discussion in surrebuttal testimony violates the Companies' due process rights. *See Dangerfield v. State*, 376 S.C. 176, 179, 656 S.E.2d 352, 354 (2008) ("The procedural component of the state and federal due process clauses requires the individual whose property or liberty interests are affected . . . the opportunity to introduce evidence, the right to confront and cross-examine adverse witnesses, and the right to meaningful judicial review.").

The procedural requirements of Act 62 are fully consistent with this well-settled precedent. It requires the Commission to vet all alternative planning recommendations as a key component of discharging its duty to determine whether the Companies' proposed IRPs "represent the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs[.]" S.C.

Code Ann. § 58-37-40(C)(1)-(2). Specifically, Act 62 unambiguously directs the Commission to "establish a procedural schedule to *permit reasonable discovery* after an integrated resource plan is filed in order to assist parties in obtaining evidence concerning the integrated resource plan, including the reasonableness and prudence of the plan *and alternatives to the plan raised by intervening parties*[.]" S.C. Code Ann. § 58-37-40(C)(1) (emphasis added). In other words, the General Assembly directed this Commission to establish a procedural schedule that would allow parties time for discovery and, importantly, would allow the Commission to meet its statutorily-prescribed obligation to issue an order on the Companies' 2020 IRPs no later than 300 days after filing. *Id.*

Here, because the deadline to file surrebuttal testimony fell just 12 calendar days before the start of the hearing, there was no time for the Parties to engage in discovery on the Synapse Alternative Plan.[5] Accordingly, the Commission agrees with the Companies that the Clean Energy Intervenors should have filed the Synapse Alternative Plan and corresponding testimony as part of their direct case. Commission Order No. 2020-715 established the procedural schedule and set the hearing date for these proceedings on October 21, 2020—over 105 days prior to the date intervenors filed their direct cases. While Witness Wilson explained that the Synapse Alternative Plan was not completed by the February 5, 2021 deadline to file direct testimony, she was unable to give any reason for the Clean Energy Intervenors' decision to prioritize meeting the North Carolina procedural schedule or why the Clean Energy Intervenors took no procedural steps in the months prior to filing surrebuttal testimony to advise other parties and the Commission of their

[5] The Commission notes that any discovery the Parties may have exchanged regarding the Synapse Report in the North Carolina proceeding is immaterial to the instant Motion. Act 62 directs the Commission to set a schedule that allows for "reasonable discovery" *in this proceeding* and notwithstanding any related discovery that may have been exchanged in another docket. In the absence of an opportunity to engage in reasonable discovery in this docket, the Commission cannot discharge its duty under Act 62.

intent to file the Synapse Alternative Plan heavily criticizing the Companies' 2020 IRPs after the date for filing direct testimony has passed. (Tr. Vol. 7, p. 2199.) In the absence of a clear explanation,[6] the Commission is unable to discern any credible reason why Synapse could not complete its analysis in the more than three months that elapsed between the Companies' November 2, 2020 update to their 2020 IRPs and the February 5, 2021 filing of intervenor's direct testimony or why the Clean Energy Intervenors failed to suggest a modification to the procedural schedule that would have allowed all parties, including the Companies, ORS and, most importantly, the Commission a reasonable opportunity to review the Synapse Alternative Plan.

The Commission is also persuaded that the Companies were prejudiced by the lack of an opportunity to fairly vet and respond to the Synapse Alternative Plan. Indeed, Witness Roberts testified that he had not been able to "thoroughly assess[ ] the Synapse Report" and "didn't have [the] chance to ask discovery questions associated with the inputs and assumptions used to run the [complex] model . . . because it was filed 12 days before the hearing." (Tr. Vol. 4, p. 1054.) Witness Wilson also recognized under cross-examination that the flaws identified in the study and analysis had not yet been presented because the Companies had not been afforded a reasonable opportunity to review the Synapse Alternative Plan and prefile responsive testimony prior to the hearing. The Commission thus finds that the late date of filing deprived the parties and the Commission the opportunity to fully vet the Synapse Alternative Plan as required by Act 62.

For all of the foregoing reasons, the Commission grants the Motion and strikes from the record the Synapse Alternative Plan and all testimony that refers to it, including the following:

(1) Surrebuttal Testimony of Rachel Wilson, witness for Natural Resources Defense Council, Sierra Club, Southern Alliance for Clean Energy, South Carolina Coastal Conservation

[6] The Commission notes that the Synapse Alternative Plan appears to have been drafted for filing in the North Carolina IRP proceeding in accordance with the procedural schedule set in Docket No. E-100, Sub 165.

League, and Upstate Forever (together, the "Environmental Parties") and Carolina Clean Energy Business Association[7];

(a) All pre-filed and live testimony (Tr. Vol. 7, pp. 2144 - 2294);

(b) Exhibit RSW-1 (H. Ex. 56) (Summary of Professional Experience); and

(c) Exhibit RSW-2 (H. Ex. 56) (Synapse Proposed Alternative Resource Plan, Corrected Version dated March 19, 2021) ("Synapse Alternative Plan").

(2) Surrebuttal Testimony of Kevin Lucas, witness for CCEBA;

(a) Pre-filed testimony Page 2, line 17 through Page 3, line 2 (Tr. Vol. 7, pp. 1911.5-1911.6 (Introducing Synapse Alternative Plan and relying on its findings and conclusions);

(b) Pre-filed testimony Page 14, line 2 through Page 21, line 12 (Tr. Vol. 7, pp. 1911.17-1911.24) (Section III, in its entirety, discussing Synapse Alternative Plan and advocating Commission rely on its analysis, findings and conclusions);

(c) Pre-filed testimony Page 47, lines 14 through 19 (Tr. Vol. 7, p. 1911.50) (advocating Commission adopt Synapse Alternative Plan);

(d) Pre-filed testimony Page 51, lines 13 through 15 (Tr. Vol. 7, p. 1911.54) (advocating Commission rely upon battery storage cost assumptions from Synapse Alternative Plan);

(e) Pre-filed testimony Page 53, lines 9 through 11 (Tr. Vol. 7, p. 1911.56) (advocating Commission rely upon Synapse Alternative Plan); and

(f) Pre-filed testimony Page 54, line 9 through Page 55, line 6 (Tr. Vol. 7, pp. 1911.57-1911.58) (advocating the Commission require Duke to rely on Synapse Alternative Plan assumptions and to develop an alternative modeling scenario that relies upon Ms. Wilson's recommendations and assumptions presented in the Synapse Alternative Plan).

(g) Live testimony Page 1909, line 18 through Page 1936, line 18; Page 1948, line 16 (Tr. Vol. 7, pp. 1909-1936, 1948) (supporting Synapse Alternative Plan and rebutting criticisms of Plan raised by Witness Roberts);

(h) Exhibit KL-S-1 (H. Ex. 50) (Synapse Alternative Plan); and

(i) Exhibit KL-S-3 (H. Ex. 50) (Proposed solar and storage addition recommendations developed using Synapse Alternative Plan).

[7] On March 10, 2021, the Commission granted SCSBA's motion to be renamed in these and other dockets as Carolinas Clean Energy Business Association ("CCEBA"). For consistency with previously filed documents, this brief will refer to SCSBA as CCEBA.

(3) Surrebuttal Testimony of John D. Wilson, witness for the Environmental Parties;

(a) All pre-filed and live testimony (Tr. Vol. 7, pp. 2090-2142);

(b) Exhibit JDW-1 (H. Ex. 53) (Summary of Professional Experience);

(c) Exhibit JDW-2 (H. Ex. 53) (Report on Implementing All-Source Procurement in the Carolinas, dated February 26, 2021); and

(d) Exhibit JDW-3 (H. Ex. 53) (Report on Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement) (together with JDW-2, the "All-Source Procurement Reports").

(4) Surrebuttal Testimony of Tyler Fitch, witness for Vote Solar;

(a) Pre-filed testimony Page 10, lines 13 through 19 (Tr. Vol. 3, p.742.10) (describing Synapse Alternative Plan report and advocating the Commission rely upon its modeling and conclusions).

(b) Live testimony Page 770, lines 14-21; Page 773, line 25 through Page 775, line 2 (Tr. Vol. 3, pp. 770, 773, 775) (supporting Synapse Alternative Plan).

2. Intervenor Recommendations to Modify 2020 IRPs

a. *Load Forecast and Resource Adequacy*

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NOS. 6-7

Summary of the Evidence

The evidence in support of this finding of fact is found in the Companies' 2020 IRPs, pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

DEC/DEP Witness Wintermantel of Astrapé testified that the Companies retained Astrapé to conduct comprehensive resource adequacy studies for both the DEC and DEP systems for use in the Companies' 2020 IRPs (the "Resource Adequacy Studies"). (Tr. Vol 2. p. 374.) Astrapé is the owner and exclusive licensor of the SERVM model, which is used by utilities and regulators nationwide to perform resource adequacy and planning studies. (Tr. Vol 2. p. 373.) As a Principal Consultant for Astrapé, Witness Wintermantel has more than a decade of experience managing resource adequacy, resource planning, and renewable integration studies across the country. (Tr.

Vol 2. p. 379.2.) According to Witness Wintermantel the purpose of a resource adequacy study is to analyze the impacts of various planning and reserve margin targets on system reliability. (Tr. Vol 2. p. 374.)

Based on results from the various scenarios and sensitivities included in the Resource Adequacy Studies, Astrapé recommended both utilities continue to plan for a minimum 17% winter reserve margin. (Tr. Vol 2. p. 379.11.) The Companies adopted this recommendation and included a 17% winter reserve margin in the development of their 2020 IRPs. (H. Ex. 1, DEC IRP Chapter 9, p. 67, DEP IRP Chapter 9, p. 68.) As Witness Wintermantel explained, this reserve margin will ensure that the Companies can reliably meet the projected normal weather peak demand even if unforeseen events occur, like unplanned outages of generating equipment, or higher than projected peak demand due to extreme weather conditions. (Tr. Vol 2. p. 379.7.) The ORS supported this decision, and ORS Witness Baron stated that the "17% winter peak reserve margin analysis meets the requirements of Act 62, is reasonable and is based on a methodology that represents a high level of sophistication." (Tr. Vol 4. p. 927.) ORS Witness Baron also noted that the Companies' 17% reserve margin is generally consistent with the target winter peak reserve margins of other utilities in the Mid-Atlantic and Southeast regions. (Tr. Vol 4. p. 928.9.) Table 10 of the ORS Reports identified that the Companies' 17% winter peak reserve margin was lower than the winter peak reserve margins for neighboring utilities DESC, Southern Company, Tennessee Valley Authority ("TVA") and Florida Power & Light Company, and lower than or equal to Louisville Gas and Electric/Kentucky Utilities. (H. Ex. 24, at 44; H. Ex. 25, at 45.)

In contrast, both the Environmental Parties and CCEBA challenged aspects of the Resource Adequacy Studies. Environmental Parties Witness James Wilson argued that the Resource Adequacy Studies overstated the winter resource adequacy risk and, as a result, overstated winter capacity needs. (Tr. Vol 3. p. 612.) According to Witness Wilson, Astrapé implemented a flawed approach to estimating the impact of extreme cold on loads by extrapolating based on observations at milder temperatures. (Tr. Vol 3. p. 616.5.) He suggested that it was in error for Astrapé to assume that when temperatures drop to extremely low temperatures, each additional degree will increase loads by the same amount. (Tr. Vol 3. p. 616.9.) He also argued that Astrapé should not have used 39 years of temperature data (1980-2018) weighted equally because the time period includes many instances of very extreme cold weather that have not occurred in decades. (Tr. Vol. 3, p. 616.5.)

In response, Witness Wintermantel explained that Astrapé used and verified regression equations based on recent historic data to extrapolate loads that would be seen at extreme cold temperatures. (Tr. Vol. 2, p. 391.17.) He also noted that Witness Wilson used the same data as Astrapé, but selected different points from which to form the regression equations. (Tr. Vol. 2, p. 391.20.) Notably, Witness Wintermantel observed that the points selected by Astrapé produced the lowest load response possible. (*Id.*) With respect to the equal weighting of 39 weather years, Witness Wintermantel explained that removing the most extreme weather years artificially deflates the reserve margin and increases the reliability risk during less extreme years resulting in increased risk to customers. (Tr. Vol. 2, p. 391.24.) Witness Snider further noted a recently released Electric Power Research Institute ("EPRI") study, which found that extreme events are occurring more, not less, frequently. (Tr. Vol. 6, p. 1586.62.) Both witnesses pointed to the recent prolonged extreme cold event in Texas—which included record setting, sub-freezing temperatures and wind chills across the state and resultant prolonged power outages from a load variance of 29% above the weather normal load forecast—as evidence of the need for utilities to plan for such exceptional events. (Tr. Vol. 2, p. 391.21, H. Ex. 62.) Witness Wintermantel highlighted that the most extreme cold weather year modeled throughout the 39-year study period was 18% above the winter weather normal forecast for DEC and 21% above the weather normal forecast for DEP, which is a much lower variance above the normal weather forecast than the variance in load seen recently in the ERCOT extreme winter event. (Tr. Vol. 2, p. 391.23.)

CCEBA Witness Olson argued that renewable resources and energy storage are undervalued as compared to firm resources such as natural gas generation in the Companies' standard installed capacity ("ICAP") planning reserve margin studies and recommended that the Companies should instead employ an unforced capacity ("UCAP") planning reserve margin. (Tr. Vol. 2, p. 485.26.) According to Witness Olson, the ICAP planning reserve margin method assumes that all firm resources are available at their full nameplate capacity and does not account for forced outage rates. (Tr. Vol. 2, p. 485.28.) By contrast, the UCAP method considers the average amount of electricity that is actually available at any given time after discounting the time that the facility is unavailable due to outages. (Tr. Vol. 2, p. 476.28, Tr. Vol. 6, p. 1586.64.) Witness Olson contends that the UCAP method is more appropriate because the Resource Adequacy Studies use the effective load carrying capability ("ELCC") to value the capacity of intermittent resources like solar and storage, and the ELCC reduces a resource's nameplate capacity to account for times when it is unable to generate electricity. (*Id.* at 485.28.)

In response, Witness Snider stated that transition to a UCAP planning reserve margin would require a significant re-design of the current planning reserve margin process. (Tr. Vol. 6, p. 1586.62.) More importantly, Witness Snider stated that use of UCAP accounting would have very little impact on the Companies' expansion plan and the selection of resources given that new thermal resources have very low forced outage rates and, therefore, is not a more reasonable or appropriate approach than the Companies' ICAP method. (*Id.*) Witness Wintermantel also highlighted that, to his knowledge, numerous other southeastern utilities use the same ICAP planning reserve margin method used by the Companies, and he was not aware of aware of any utilities in the Southeast region that are using the UCAP method. (Tr. Vol. 2, p. 470.)

Commission Conclusions

Resource adequacy and capacity to serve anticipated peak electrical load and applicable planning reserve margins are, together, one of the seven factors Act 62 directs the Commission to balance when considering a utility's proposed IRP. S.C. Code Ann. § 58-37-40(C)(2)(a). The Commission is persuaded by and agrees with the testimony of DEC/DEP Witness Wintermantel and ORS Witness Baron that the Resource Adequacy Studies and resulting 17% winter peak reserve margin meets the requirements of Act 62, is reasonable, and represents a high level of methodological sophistication. As Witnesses Wintermantel and Snider explained, lowering the target planning reserve margin below 17% in the winter, as the Environmental Parties appear to advocate, would result in less generation available to meet load and create risks for customers during extreme cold weather events due to increased loss of load risk. This point resonates strongly with the Commission in light of the evidence presented by ORS demonstrating that the 17% reserve margin is, in many cases, *lower than* the winter peak reserve margins of other neighboring Southeast utilities. As the recent cold weather event in Texas underscores, utilities must plan and prepare for extreme weather events, however rarely they may occur.

With respect to CCEBA's recommendation that the Companies should transition from ICAP to UCAP modeling, the Commission finds Witness Snider's testimony to be credible that continuing to utilize the ICAP approach is reasonable and appropriate and UCAP planning would have little meaningful impact on the Companies' selection of resources. The Commission also notes Mr. Snider's uncontroverted testimony that transitioning to ICAP would require a significant re-design of the current planning process, as well as Witness Wintermantel's uncontroverted testimony that the Companies' ICAP method is consistently used by all other utilities in the southeastern region.

For all of these reasons, the Commission finds that challenges to the Resource Adequacy Studies and reserve margins raised by the Environmental Parties and CCEBA do not present any alternative recommendation that is more reasonable and appropriate to ensure future resource adequacy than the Companies' Resource Adequacy and current plans. Moreover, the Environmental Parties' suggestion that the Companies' winter peak reserve margin is too high fails to appropriately balance power supply reliability as required by Section 58-37-40(C)(2)(d) of Act 62. Accordingly, the Commission finds that the Resource Adequacy Studies are reasonable and meet the requirements of Act 62.

b. *Natural Gas Price Forecasts*

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 8-9

Summary of the Evidence

The evidence in support of this finding of fact is found in the Companies' 2020 IRPs, pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

Witness Snider explained that the Companies' 2020 IRPs forecast the future cost of natural gas by relying upon ten years of forward natural gas market price data before transitioning to commodity price estimates derived based upon fundamental forecasts over the remaining planning period. (Tr. Vol. 6, pp. 1586.66-67.) More specifically, the market-based forecast came from a NYMEX natural gas price strip actually purchased by the Companies on April 9, 2020, which the Companies used as their market assumptions for 2020-2030. (*Id.*) Beginning in 2031, the natural gas price strip was blended with a long-term fundamental natural gas price forecast that the Companies obtained from their vendor, IHS Markit ("IHS"). (*Id.*) Beginning in 2035, the forecast is based entirely on the IHS fundamentals forecast. (Tr. Vol. 6, pp. 1586-67-68.) This natural gas price forecasting methodology was discussed in the 2020 IRPs. (Ex. 1 DEC 2020 IRP, at 157-158, DEP 2020 IRP, at 157.)

On behalf of ORS, Witness Hayet explained that Kennedy Associates extensively reviewed the methodological approach to natural gas price forecasting and the Companies' resulting low, base, and high natural gas price forecast assumptions. (Tr. Vol. 3, pp. 856.13.) As part of this review, Witness Hayet compared the Companies' natural gas price forecast assumptions to those assumptions utilized by six other regulated utilities, including DESC, Dominion Energy Virginia, and the TVA, among others, and performed benchmarking to natural gas forecasts in the EIA's 2020 Annual Energy Outlook ("2020 AEO"). (Tr. Vol. 3, pp. 856.13-14; Ex. 24, DEC ORS Report, pp. 46-47, Fn. 57-63; DEP ORS Report, pp. 46-47, Fn. 57-63.) Based on this analysis, ORS found that the Companies' forecasts are lower "by a small amount" over the planning period as compared to these other recent utility and industry forecasts released since December 2019 but "do not appear to be unreasonable," commenting that "the important question is whether DEP's forecasts are outliers when compared to the other forecasts, and the answer is no." (Tr. Vol. 3, p. 856.14; Ex. 24, DEC ORS Report, p. 49; DEP ORS Report, p. 49.) Nevertheless, ORS recommended that the Companies review their natural gas price forecasting methodology and investigate alternative approaches through a stakeholder process before the Companies' next comprehensive IRP. (Tr. Vol. 3, p. 856.14; Ex. 24, DEC ORS Report, p. 51; DEP ORS Report, p. 51.) On behalf of the Companies, Witness Snider agreed to this recommendation. (Tr. Vol. 6, pp. 1586.64-65.)

CCEBA Witness Lucas challenged the Companies' natural gas forecasting methodology, arguing that it contains "major flaws" and that the Companies should utilize only eighteen months of market based prices before transitioning to a fundamentals forecast. (Tr. Vol. 2, p. 502.86.) Witness Lucas is the Senior Director of Utility Regulation for the Solar Energy Industry Association ("SEIA"), a national solar industry trade association with the stated goal transitioning 20% of all U.S. electricity generation to solar generation—which does not rely upon natural gas—by 2030. (Tr. Vol. 2, p. 505.06.) To support his proposal for limited use of market based prices, Witness Lucas argues that (1) it is not reasonable for the Companies to base their projected market fuel prices entirely on their ability to purchase "*de minimis*" quantities of natural gas on ten-year contracts as such prices are not reflective of the price to actually secure a comparable volume of natural gas, (Tr. Vol. 2, pp. 501.65, 1911.34-35.); and (2) futures prices for natural gas are highly volatile and do not provide a reliable metric for projecting future costs. (Tr. Vol. 2, p. 502.75.) Witness Lucas also suggests that the Companies' use of ten years of market-based pricing before transitioning to fundamental forecasts "repeatedly ignore[s] the directive of the NCUC" which limits the use of market-based pricing to eight years; and that the Companies' concerns about overpayment risks to solar QFs associated with reliance on lagging fundamental forecasts is speculative and already being addressed. (Tr. Vol. 7, pp. 1911.32-33.)

Witness Snider defended the Companies' reliance on ten years of market-based pricing by explaining that fundamental price forecasts have lagged the market price over the past decade, (Tr. Vol. 6, pp. 1586.75-77, 1658.)—a statement that Witness Lucas acknowledged was "fair" on cross examination. (Tr. Vol. 3, p. 542.) Witness Snider noted that the historic use of fundamental price forecasts has resulted in significant "overpayment risk" and excess costs to customers both historically and on a prospective basis. (Tr. Vol. 6, p. 1586.68.) According to Witness Snider, the Companies have increasingly relied upon market prices since 2015 as the market for natural gas has become increasingly liquid and fundamentals forecasts have shown to be overpriced as natural gas prices continually decline. (Tr. Vol. 6, pp. 1586.72-74.) Overpayment risk arises as the market price for power changes over the life of a long-term fixed price power purchase agreement ("PPA"), locking the Companies into paying for a facility's power at stale avoided cost rates. (*Id.*) According to Witness Snider, the Companies' recent analysis suggest that realized overpayments for fuel costs in 2020, alone, are approximately $170 million in excess of the actual value the solar provided customers. The Commission also recently recognized and relied upon the Companies' testimony in the 2019 Avoided Cost Dockets demonstrating that future solar QF over-payment obligations were projected to be over $2 billion dollars at that time. (*Id.*)

Witness Snider also directly contradicted Witness Lucas's testimony on the NCUC's prior acceptance of the same methodology in prior North Carolina IRP proceedings. Witness Snider explained that DEC and DEP have used 10 years of forward market pricing in their last six IRP filings in North Carolina and South Carolina and, contrary to Witness Lucas's testimony, the NCUC has never rejected that methodology for IRP purposes. (Tr. Vol. 6, p. 1586.79.) This is the first time this issue has been raised in a SC IRP proceeding. Witness Snider also pointed out that "[i]n the context of avoided cost proceedings, the Companies have advocated for using the same 10 years of market pricing data consistent with the IRP filings. This Commission and ORS accepted this methodology in the 2019 avoided cost proceeding, while the NCUC at this point has settled on eight years of market before relying on fundamental forecasts as appropriate for avoided cost purposes." (*Id.*)

Witness Snider also highlighted that the NCUC had shared the Companies' concerns in prior North Carolina avoided cost proceedings about undue reliance on fundamental forecasts. The NCUC had specifically found in 2016 that "lagging fundamental forecast pricing has proven to be inaccurate over the past few years and has led to overpayment to QFs" and that "undue reliance on higher fundamental forecast prices when a demonstrated liquid market exists can lead to arbitrage . . ."[8] (Tr. Vol. 6, pp. 1579, 1586.70-71.)

On cross-examination, Witness Lucas's testimony on this last point was wholly discredited by showing that the NCUC had consistently accepted DEC's and DEP's natural gas price forecasting methodology based on ten years of market-based pricing, followed by a four-year blending period from market to fundamental forecasting in each of the Companies' annual IRP filings from 2015 to present. (Tr. Vol. 7, p. 1960; H. Ex. 48.) Witness Snider confirmed that his testimony was accurate and reflective of the NCUC's consistent determinations in reviewing the Companies' 2015, 2016, 2017, 2018, and 2019 IRPs and IRP Updates that the Commission had accepted the Companies' fuel forecasting methodology of using 10 years of market price data before transitioning to fundamental forecasts—which is the precise issue that CCEBA's Mr. Lucas challenges here. (Tr. Vol. 6, pp. 1832-1836; Ex. 48.)

Commission Conclusions

The Commission finds that the natural gas price forecasts used in developing the Companies' 2020 IRPs are reasonable for planning purposes and that the 2020 IRPs meet the requirements of § 58-37-40(B)(1)(b) to conduct fuel cost sensitivities under various reasonable scenarios. In keeping with their obligation under Act 62, the Companies developed three natural gas price forecasts, including a low, base, and high forecast using a model that blended a market-based forecast with a fundamentals-based forecast. The Companies reasonably relied on market price data for 10 years, as well as longer-term fundamental forecasts. While the Commission notes ORS's comment that the Companies' forecasts are lower "by a small amount" over the planning

[8] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 77, N.C.U.C. Docket No. E-100, Sub 148 (Oct. 11, 2017) ("N.C.U.C. Sub 148 Order"); *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 58, N.C.U.C. Docket No. E-100, Sub 158 (Apr. 15, 2020).

period as compared to other recent utility and industry forecasts released since December 2019, (Tr. Vol. 3, p. 856.13; Ex. 24 ORS DEC Report at p. 49.), the Commission agrees with ORS that the forecasts are not outliers and appear reasonable for planning purposes.

Moreover, the Commission finds credible Witness Snider's testimony regarding the overpayment risk of relying too heavily upon lagging fundamentals-based forecasts. Witness Snider's testimony demonstrates that fundamental forecasts have been less accurate than market-based projections in recent years. Consequently, based upon all of the evidence in the record, the Commission finds that Witness Lucas's recommendation that the Companies use only 18 months of market-based prices is not more accurate or appropriate than the Companies' methodology and fails to properly balance commodity price risks as required under § 58-37-40(C)(2)(e).

Particularly based on ORS's investigation and Witness Hayet's testimony, the Companies' forecasts appear largely in line with the forecasts of similarly situated utilities. The Commission also finds that the record is clear that the natural gas price forecasting methodology DEC and DEP used in their 2020 IRPs is the same methodology accepted by the NCUC in recent IRP proceedings from 2015 to 2019. *See* Ex. 48.

Based upon all of the foregoing, the Commission accepts the 2020 IRPs' natural gas price forecasting methodology as reasonable for planning purposes in this proceeding. However, the Commission supports the agreement between the Companies and ORS to discuss natural gas forecasting methodology and potential alternatives with stakeholders before the Companies' next comprehensive IRP in 2022.

c. *Coal Retirement*

EVIDENCE AND CONCLUSIONS TO SUPPORT FINDING OF FACT NOS. 10-11

The evidence in support of these findings of fact are found in the Companies' 2020 IRPs, pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

The Companies prepared detailed analyses of both the most economic and earliest practicable retirement options for DEC's and DEP's operating coal generation units. These detailed analyses had previously been mandated by the NCUC in a prior North Carolina IRP proceeding. (Tr. Vol. 6, p. 1586.91.)

The two Base Case Portfolios as well as the No New Gas Portfolio use the retirement dates from the most economic coal retirement analysis found in Table A-1 of the DEC IRP and DEP IRP. These most economic retirement assumptions include retirements of the Companies' coal-fired resources in 2022, 2024, 2026, 2031, and 2035 for DEC and 2026, 2028, and 2029 for DEP. (Tr. Vol. 1, p. 62.15; Ex. 1 DEC 2020 IRP, p. 147; DEP 2020 IRP, p. 146; H. Ex. 24, at 78; H. Ex. 25, at 78.) The remaining three portfolios rely on accelerated coal retirement dates, which are accelerated to the earliest practicable dates in order to address more aggressive potential carbon reduction targets. (*Id.* H. Ex. 24, at 77; H. Ex. 25, at 79.) With the exception of Cliffside Unit 6,[9] the 2020 IRPs plan to retire all coal units in both systems before 2030 under both retirement scenarios. (Tr. Vol. 1, p. 62.17.)

The ORS found that the Companies conducted a detailed coal retirement analysis as part of their 2020 IRPs. (H. Ex. 24, at 61; Ex. 25, at 62.) Nevertheless, Witness Hayett on behalf of ORS, recommended that the Companies provide evidence that the optimal retirement dates that were determined with the Sequential Peaker Method are comparable to the optimal retirement dates the System Optimizer model would produce if it were used in the retirement study. (Tr. Vol. 3, p. 856.17.) DEC/DEP Witness Snider provided a detailed explanation of the Sequential Peaker Method approach in his rebuttal testimony and expressed a willingness for the Companies to collaborate with stakeholders to potentially enhance the modeling process given that

[9] DEC's Cliffside Unit 6 is assumed to operate exclusively on natural gas by 2030 in the portfolios where the earliest practicable coal retirement schedule is used. (Ex. 24, at 78.)

the Companies will be switching to the new Encompass optimization modeling. (Tr. Vol. 6, pp. 1586.91-100.) The ORS found the Companies' response to be satisfactory and confirmed that no further action is necessary during this IRP. (Tr. Vol. 7, pp. 2307.9, 16.)

In contrast, Witness R. Wilson argued in her surrebuttal testimony and as part of the Synapse Alternative Plan that the Companies' coal retirement analysis does not properly account for the cost and benefits of the coal-fired capacity and energy and thus fails to produce the most "economic" retirement date for individual units and for combinations of units. (Tr. Vol. 7, p. 2151.9; H. Ex. 56, at 1.) Witness Wilson's conclusion that the Companies' coal units perform poorly was based, in part, on her review of the average annual capacity factors for the Companies' coal facilities, many of which were below 10%. (H. Ex. 56, at 6.)

DEC/DEP Witness Roberts, however, explained that it was misleading to rely on the *annual* average capacity factor because many of the Companies' coal facilities operate as "peaking units" which are intended to provide capacity during peak cold weather events when renewable and other resources may not be able to serve the systems' load. (Tr. Vol. 4, p. 1058.) By way of example, Witness Roberts explained that many of the coal units operated at 100% capacity during an extreme cold weather event that took place between January 2, 2018, and January 8, 2018. (Tr. Vol. 4, p. 1058; H. Ex. 31, at 1.) Indeed 12 out of the 18 coal units identified in the Synapse Alternative Plan operated with a capacity factor of more than 90%, and all units operated with a capacity factor at or above 60% in the same time period. (*Id.*)

Because Witness Wilson's opinions and recommendations regarding the Companies' coal retirement plans were presented for the first time in her surrebuttal testimony and as part of the Synapse Alternative Plan, they are within the scope of the renewed Motion to Strike filed by the Companies on June 9, 2021.

Commission Conclusions

An important component of an IRP and a specific requirement of Act 62 is that utilities must develop portfolios to fairly evaluate retirements of existing resources, which would include when the planned retirement of operating coal units would be in the best interest of customers, particularly as the utilization of those generating resources diminishes over time. The Commission finds that the Companies' detailed analysis of both the most economic and earliest practicable retirement options for DEC's and DEP's operating coal generation are reasonable for planning purposes and meet the requirements of Section 58-37-40(B)(1)(f) to analyze the remaining estimated life of operation for each operating generating facilities in the Companies' portfolios. The Commission further finds that the Companies' Base Plan Portfolios reasonably plan for the most economic approach to coal retirements and notes that the ORS accepted the Companies' coal retirement analyses for purposes of this proceeding. The Companies should continue to analyze the cost and reliability impacts of planning for earlier retirement of DEC's and DEP's operating coal generation plants as part of their ongoing resource planning assessment should emerging environmental policy or changing market conditions negatively alter the economic viability of the Companies' coal units relative to the analyses presented in this proceeding.

For the reasons stated in support of Finding of Fact No. 5, the Commission grants the Companies' renewed Motion to Strike the Synapse Alternative Plan and corresponding testimony. Because Witness Wilson's arguments regarding the Companies' coal retirement plans were improperly presented in her surrebuttal testimony and as part of the Synapse Alternative Plan, the Commission need not reach a decision on the merits as the arguments are stricken from the record.

d. *Planning for New Natural Gas Capacity*

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NOS. 12-13

Evidence in Support

The evidence in support of this finding of fact is found in the Companies' 2020 IRPs, pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

Witness Roberts and Witness Snider explained that natural gas generation plays a critical role in ensuring the reliability, resiliency, and affordability of electric service in the Carolinas, while facilitating the reliable integration of additional solar and wind generation resources as the Companies transition to lower CO_2 emissions and net-zero emissions by 2050. (Tr, Vol. 4, p. 1052.5, Tr. Vol. 6, p. 1565.100.) While the Companies are national leaders in installed solar generation and continue to experience significant solar growth, (Tr, Vol. 4, p. 1052.17, Tr. Vol. 6, p. 1565.102.), natural gas-fired generation is a proven and cost-effective dispatchable technology that has a long history of reliably serving customers with the ability to provide baseload, intermediate, and peaking energy needs in a flexible manner. (*Id.*) Witness Snider explained that customer demand, at the time of the DEC and DEP system peaks, is not correlated with solar generation output in the Carolinas. Accordingly, a firm, dispatchable resource like natural gas is needed to flexibly supplement intermittent resources like solar and wind on an as needed basis. (Tr. Vol. 6, pp. 1565.102-05.) This is particularly true in winter months as peak demand occurs early in the morning when little to no solar energy is available or reliably dependable. (*Id.*) To meet demand in the Carolinas, Witness Snider explained, gas must ramp up several hours before solar output starts, turn down as solar output climbs during the day, and then come back on or turn up in the evening as the sun sets. (*Id.*)

According to Witness Snider, the 2020 IRPs demonstrate that a diverse mix of resources is needed to meet growing system demand and to replace the energy and capacity from retirements of older less efficient units. (Tr. Vol. 6, pp. 1565.100-01.) Planning for a mix of complementary new low- or no-carbon resources and reliable and proven dispatchable technologies, such as natural gas, is critically important for ensuring reliability and de-risking the transition as compared to a transition that relies on a single or narrow scope of technologies. (*Id.*)

Witness Roberts highlighted that the Companies' continued planning for dispatchable natural gas generation is supported by and consistent with the position taken by James Robb, President and CEO of the North American Electric Reliability Corporation ("NERC") in testimony before the United States Senate Committee on Energy and Natural Resources in March 2021. Mr. Robb's testimony to Congress highlighted the importance of gas generation to resource portfolios:

> Natural gas is essential to a reliable transition. As variable resources continue to replace other generation sources, natural gas will remain essential to reliability. In many areas, natural gas-fueled generation is needed to meet energy demand during shoulder periods between times of high and low renewable energy availability. And on a daily basis in areas with significant solar generation, the mismatch between the solar generation peak and the electric load peak necessitates a very flexible generation resource to fill the gap. Natural gas generation is best positioned to play that role. The criticality of natural gas as the "fuel that keeps the lights on" will remain unless or until very large-scale battery deployments are feasible or an alternative flexible fuel such a hydrogen can be developed.

(*Id*. at 1043, 1052.5; H. Ex. 33, p. 9, 10.)

Both CCEBA Witness Lucas and Vote Solar Witness Fitch criticized the Companies' plans for new natural gas generation, suggesting that it is inconsistent with the Companies' goal to reach net-zero carbon emissions by 2050 and likely would result in stranded asset costs for ratepayers if new natural gas generation was forced to be retired early due to future changes in environmental regulations. (Tr. Vol. 3, pp. 502.22, 733.) Witness Fitch's testimony relied upon a report he authored as a fellow of the Energy Transition Institute entitled *Carbon Stranding: Climate Risk and Stranded Assets in Duke's Integrated Resource Plan* (the "Carbon Stranding and Climate Risk

Report"). (Ex. 22.) His analysis of the Companies' planned investments in new gas generation under the Base Case With Carbon Policy Portfolio assumed a sustained high level of carbon emissions through 2050 unless the Companies retired those new units well in advance of the end of their useful lives. (Tr. Vol. 2, p. 502.69.) Citing concerns regarding the effectiveness of negative emissions technologies and carbon offsets, Witness Fitch further assumed early retirement of gas assets would be necessary to reach the net-zero target and estimated that the Companies' plan for constructing new natural gas assets under the 2020 IRPs could lead to stranded asset costs of as much as $4.8 billion. (Tr. Vol. 2, pp. 502.70, 502.74.) Witness Fitch also asserted that the Companies should avoid moving forward with investments in generation, distribution, and transmission that could be deferred or displaced by DERs if the analytical capabilities of Integrated System & Operations Planning ("ISOP") were in place. (Tr. Vol. 3, p. 736.56.)

In response, DEC/DEP Witnesses Santoianni explained that the Companies' plans do not create stranded asset risk as suggested by Witness Fitch, while Witness Snider points out that Witness Fitch only considered such risks for natural gas resources and failed to consider such risks for other resources such as battery storage and solar resources. (Tr. Vol. 5, pp. 1532-1533, 1536.5; Tr. Vol. 6, p. 1572.) Witnesses Snider and Roberts underscored the importance of natural gas generation as a critical bridge to ensuring system reliability as DEC and DEP plan to integrate significant levels of variable and intermittent solar over the planning period. (Tr. Vol. 6, pp. 1586.104-109; Tr Vol. 4, pp. 1052.23-26.)

Addressing Witness Fitch's stranded asset claims, Witnesses Santoianni and Snider explained that Witness Fitch's claims are misleading, biased and inaccurate as the Companies will not be forced to "strand" new gas resources to meet their carbon reduction goals. (*Id.* at 1532; Tr.

Vol. 6, pp. 1565.105.) Witness Snider testified that Mr. Fitch's entire premise that natural gas assets will be "stranded" under the 2020 IRPs is simply false. He testified that the 2020 IRPs reasonably modeled natural gas units based on their planned lifespan and the results determined adding new natural gas to be least cost. Transitioning the fleet away from coal and meeting future load growth in the Carolinas without building new gas units, as shown in the 2020 IRPs is the most expensive option for customers and will likely require coal units to operate longer. Witness Snider also explained that the 2020 IRPs had also evaluated sensitivities where new natural gas generation additions were operated for a shorter 25-year useful life and these investments were still determined to be least cost. (Tr. Vol. 6, p.1565.)

Witness Santoianni explained that the IRPs reflect the 35-year useful lives for natural gas assets based on the life cycle appropriate for use in today's planning. (Tr. Vol. 5, p. 1532.) She explained that the Companies specifically analyzed this aspect in their IRPs, by assuming a reduced 25-year book life for new gas units (from a base assumption of 35 years) and that the Duke Energy Climate Report examined their economic value under a net zero target. That net zero analysis showed that gas units still were used and useful through 2050, continued to provide capacity value and called on to maintain reliability. (Tr. Vol. 5, p. 1536.14.)

Witnesses Santoianni and Snider also criticized many aspects of the assumptions and modeling that Mr. Fitch used to develop the Carbon Stranding and Climate Risk Report. First, they noted that the Report failed to run any production cost modeling. (Tr. Vol. 3, p. 1036.13; Tr. Vol. 6, p. 1586.111.) By failing to model hourly electricity load, the Carbon Stranding Report ignores the most basic purpose of the 2020 IRPs: to plan a system that serves customer load reliably every hour. In addition, Witnesses Santoianni and Snider explained that the Carbon Stranding Report relies on unrealistic assumptions for future emissions and operation of fossil units, assuming a simplistic straight-line emissions trajectory and rudimentary decision process to artificially inflate the calculation of stranded costs. (Tr. Vol. 5, p. 1536.13; Tr. Vol. 6, p. 1586.107.) Specifically, the Carbon Stranding and Climate Risk Report assumes that coal and natural gas units will continue to operate through 2050 at the same levels that they did in 2016-2018. (Tr. Vol. 5, p. 1036.15; Tr. Vol. 6, p. 1586.111.) Witness Santoianni explained that this modeling assumption is inconsistent with both the Companies' 2020 IRPs and the Duke Energy Climate Report, which clearly show an evolving role for natural gas units as coal is retired and more renewable energy and energy storage is added to the Companies' systems. (*Id.*) By 2050, Duke Energy's Climate Report shows that natural gas units will provide about 6% of generation, and the Carbon Stranding Report acknowledges that operating gas units at low capacity factors (on the order of 5%) "contributes very little to total emissions." (Tr. Vol. 5, p. 1536.15.) Witness Fitch also did not consider dual-fuel capability or the potential for hydrogen blending for reducing emissions. (Tr. Vol. 4, p. 1536.16.) For example, Witness Snider noted that the Companies' most efficient coal units have been retrofitted in recent years with co-firing capability to increase their flexibility, de-risk fuel costs, and generate electricity with a lower carbon intensity. (Tr. Vol. 6, p. 1586.112.) Witness Snider argued that the same trend would hold true in the future. (*Id.*)

Finally, Witness Santoianni noted that other modeling efforts by well-established and respected organizations, including the National Renewable Energy Laboratory's ("NREL") Carbon-Free Resource Integration Study[10] and the Princeton University Net-Zero America

[10] Sergi, B., B. Hodge, D. Steinberg, G. Brinkman, S. Haase, M. Emmanuel, and O. Fernandez. Duke Energy Carbon-Free Resource Integration Study: Capacity Expansion Findings and Production Cost Modeling Plan. NREL/PR-5D00-78386. NREL, Nov. 10, 2020.

research[11] show a continued role for new natural gas capacity, even if carbon policy that restricts future emissions is enacted. (Tr. Vol. 5, pp. 1536.17-18.)

Witness Roberts emphasized that—as highlighted by NERC's President and CEO to Congress—natural gas generation "will remain essential to reliability" and is needed to ensure the Companies meet their obligations as independent balancing authorities under NERC Reliability Standards.[12] (Tr. Vol. 4, p. 1052.11.) He stressed that the Companies have the public service obligation to plan and operate their generating fleets and transmission and distribution systems to provide reliable power system operations to their customers 24 hours per day, 7 days per week, 52 weeks per year. (Tr. Vol. 4, p. 1536.1052.5.) As part of this responsibility and their legal obligation under the NERC Reliability Standards, the Companies must maintain demand and resource balance within their respective balancing authority area and must additionally provide their shares of frequency support for the Eastern Interconnection. This includes maintaining frequency within predefined limits every 30 minutes under all conditions. (Tr. Vol. 4, p. 1052.11.) Importantly, Witness Roberts noted that neither Witness Lucas, Witness Fitch, nor any other intervenor witness appeared to consider or otherwise analyze the Companies' obligations to comply with the NERC Reliability Standards when recommending such significant changes to the Companies' IRPs. *(Id.)*

Witness Roberts also emphasized, based on his over 20 years of experience operating the power system and being accountable for NERC compliance, that natural gas generation is needed to address the variability and intermittency of solar generation and to ensure sufficient capacity is

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[11] E. Larson, C. Greig, J. Jenkins, E. Mayfield, A. Pascale, C. Zhang, J. Drossman, R. Williams, S. Pacala, R. Socolow, EJ Baik, R. Birdsey, R. Duke, R. Jones, B. Haley, E. Leslie, K. Paustian, and A. Swan, Net-Zero America: Potential Pathways, Infrastructure, and Impacts, interim report, Princeton University, Princeton, NJ, December 15, 2020.

[12] Congress mandated compliance with the NERC Reliability Standards through the federal Energy Policy Act of 2005, which enacted in response to the August 2004 that impacted nearly 50 million people in the Northeastern United States and Canada. (*Id.* at 1052.7.)

available during winter mornings when DEC and DEP have their greatest loss of load risk. Witness Roberts explained that output from solar facilities in winter in the Carolinas is especially challenging to plan for, and is not dependable day-ahead and even intra-hour unless a clear, blue-sky day is guaranteed. (Tr. Vol. 4, p. 1536.18.) Witness Roberts also highlighted the limited capacity value of solar during winter mornings, testifying that the capacity factor for solar in the DEP system during a seven day period in February 2021 ranged between just 3.44% and 6.06% as compared to an average of 14%-17% and 15%-16%, respectively, for the winter months of January and February and 22%-28% and 28%-31%, respectively, for the summer months of June through August. (*Id.* at 1052.19-19.) Finally, Witness Roberts explained that while battery storage is a useful tool, it is limited by the availability of solar energy needed to charge it as well as the duration and size of the battery. (Tr. Vol. 4, p. 1052.24.) With current technology, it is not a continuous, dispatchable resource that can provide capacity and serve customers' energy needs during prolonged periods of cloud cover which are not uncommon in the Carolinas during winter months. (Tr. Vol. 4, pp. 1052.29-30, 1111.)

In sum, Witness Snider explained that natural gas units were reasonably modeled based on their appropriate lifespan and because cost-effective use of gas units will reduce emissions and help meet the Companies' corporate climate goals while maintaining power system reliability. (Tr. Vol. 6, pp. 1586.110-111.) As shown in the 2020 IRPs, transitioning the fleet away from coal and meeting future load growth in the Carolinas without building new gas units is the most expensive option for our customers and will likely require coal units to operate longer. (*Id.*)

As related to moving forward with system investments while ISOP is in development, Witness Oliver provided testimony that delaying such investments is not prudent, practical, or necessary. Witness Oliver stated that placing a requirement on the Companies to perform extensive, complex analyses on these existing projects could hinder the Companies' ability to complete them in a timely manner, resulting in delays that could be detrimental to reliability and resilience for customers. (Tr. Vol. 5, pp. 1331.8-9.)

<u>Commission Conclusions</u>

Act 62 directs the Commission to consider whether an IRP adequately plans for power supply reliability. S.C. Code Ann. Section 58-37-40(C)(2)(d). The Commission finds credible the testimony of Witnesses Roberts, Snider, and Santoianni that new natural gas is critically important to the Companies' plan to ensure system reliability, as the Companies' 2020 IRPs plan to retire their significant operating coal fleets and to add significant variable and intermittent solar and other renewable energy resources during the planning period. Based on the testimony of the DEC/DEP witnesses as well as positions taken by well-respected industry organizations, including the recent testimony of Mr. Robb to Congress on behalf of NERC, the Commission is persuaded that natural gas resources paired with renewables, storage, and other emerging technologies offer the potential to balance reliability, affordability, and the environment as the Companies transition towards a net-zero carbon future.

Moreover, the Commission finds the errors pointed out by DEC/DEP witnesses to the Carbon Stranded Report, to be significant and concerning. That Witness Fitch failed to consider the evolving role of natural gas as explained in the Companies' IRPs and the Climate Report casts doubt on the entirety of his analysis. He also fails to reasonably address that the 2020 IRPs determined new natural gas resources to be part of least cost portfolios, both based upon environmental regulations that exist today as well as in planning for potential future carbon regulation. The Commission also finds significant that the Companies developed a "no new gas" scenario in the 2020 IRPs, but determined that plan would impose the highest costs on customers and is dependent upon the future uncertain development and commercial maturity of dispatchable, zero-emitting technologies. Thus, the Commission finds that Vote Solar's and CCEBA's challenges to the 2020 IRPs' planning for new natural gas do not support rejecting the IRP or requiring a modified IRP. In reaching this conclusion, the Commission notes that ORS did not express an opinion on this issue, but advocated its belief that the 2020 IRPs, as a whole, were "reasonable."

Finally, we find credible Witness Oliver's testimony that delaying system investments while ISOP is in development could compromise system reliability, and that no evidence was presented to the contrary.

For all of these reasons, the Commission finds good cause to approve the Companies' 2020 IRPs to the extent they plan for new natural gas generation.

a. *Solar, Wind, and Battery Storage Cost and Modeling Assumptions*

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NOS. 15-19

<u>Summary of the Evidence</u>

The evidence in support of these findings of fact is found in the 2020 IRPs, the testimonies and exhibits of DEC/DEP witnesses Kalemba, Wintermantel, and Snider; CCEBA witnesses Lucas and Olson; and the entire record in this Docket.

DEC/DEP Witness Kalemba explained the solar, wind, and battery storage assumptions that the Companies used in development of the 2020 IRPs. (Tr. Vol. 2, p. 315.) He explained that Act 62 requires utilities to evaluate three levels (low, medium, and high) of renewable energy in their IRPs. (Tr. Vol. 2, p. 316; S.C. Code Ann. § 58-37-40(B)(1)(e).) To meet these requirements, the Companies prepared base, high, and low cases for the inclusion of renewables in their 2020 IRPs. (Tr. Vol. 2, p. 316.) Each of the six portfolios relies on either the base or high cases for renewables. The base renewables case is used for three portfolios: the Base with Carbon Policy portfolio, the Base without Carbon Policy portfolio, and the Earliest Practicable Coal Retirement portfolio. The high renewables case is used for the remaining three portfolios. (*Id.*) In addition, Witness Kalemba explained that the high and low renewables cases were each tested as sensitivities against the base renewables case in the Base with Carbon Policy portfolio to assess the impact on that portfolio. (Tr. Vol. 2, p. 316-17.) Witness Kalemba explained that evaluating sensitives can help Commissioners, policy makers, customers, intervenors, and the Companies see the impact of a wide range of variables in addition to those evaluated in the six portfolios. (Tr. Vol. 5, p. 1390.5.) Witness Kalemba testified that the amount of renewable energy, and solar in particular, shown in the Companies' IRPs is significant. (Tr. Vol. 5, p. 1390.4.) The amount of total solar expected by 2035 is approximately 8,600 MW in the Base without Carbon Policy portfolio and approximately 12,300 MW in the Base with Carbon Policy portfolio. (Tr. Vol. 5, p. 1390.5.)

With respect to battery storage, the Companies' IRPs considered both standalone storage as well as storage paired with solar. (Tr. Vol. 2, p. 325.17.) In developing the cost projections for battery storage, the Companies evaluated a number of industry cost projections published by sources such as the National Renewable Energy Laboratory ("NREL"), Lazard, and Pacific Northwest National Laboratories to compare the Companies' battery storage cost projections to those of the industry. (Tr. Vol. 2, p. 325.18.) Based on this benchmarking, the Companies made adjustments to the battery storage cost projections to better align with published cost projections. (*Id.*).

Witness Kalemba also explained that the Companies engaged Astrapé to conduct the 2020 Storage Effective Load Carrying Capability study (the "Storage ELCC Study") to evaluate the capacity value that storage resources can provide towards meeting the Companies' winter peak demand. (Tr. Vol. 2, p. 325.20.) The Companies used the results of the study to calculate the capacity value of adding incremental blocks of battery storage across the various portfolios. (Tr. Vol. 2, p. 325.21.)

CCEBA witnesses Lucas and Olson criticized several aspects of the Companies' modeling, suggesting that they overinflate the cost and underrepresent the value of solar in the Companies' IRPs.

Solar Cost Assumptions

CCEBA Witness Lucas found that the Companies "capital cost assumptions for solar are reasonable" but recommended that the Companies implement a 19% cost reduction to the Companies' fixed O&M costs for solar because the Companies' solar capital cost projections are approximately 20% less than the NREL annual technology baseline ("ATB") Moderate case. (Tr. Vol. 2, p. 501.34.) In response, Witness Kalemba explained that the Companies did not develop their capital costs to be intentionally 20% less than NREL ATB Moderate case and instead specifically developed solar costs to represent the cost to construct and operate a solar facility in the Carolinas. (Tr. Vol. 5, p. 1390.10.) Accordingly, he explained that application of a 20% reduction to the NREL ATB fixed O&M costs, as recommended by Witness Lucas, merely because the Companies' solar capital costs were 20% below NREL, would result in fixed O&M costs that are not representative of forecasted fixed O&M costs in the Carolinas. (Tr. Vol. 5, p. 1390.10-11.) In addition, Witness Kalemba explained that the Companies performed low and high solar cost sensitivities that demonstrated the 19% cost reduction recommended by Witness Lucas would have limited impact on the amount of solar selected in the 2020 IRP. (Tr. Vol. 5, p. 1390.12.)

Battery Cost Assumptions

CCEBA Witness Lucas also argued that the Companies' battery storage cost assumptions are inflated as compared to other sources, arguing that the Companies appear to "double count" costs associated with battery replenishment needed to address battery degradation that occurs over time. (Tr. Vol. 2, p. 497.) Witness Lucas argues that the Companies should use the battery costs from the NREL ATB Advanced scenario. (Tr. Vol. 2, p. 501.48.)

In response, Witness Kalemba explained that NREL ATB cases can provide helpful information in assessing industry trends but that it should not be used in long-term resource planning as "absolute" costs that accurately reflect the costs expected by a particular utility. (Tr. Vol. 5, p. 1390.10.) Witness Kalemba also explained that the Companies' starting points for battery storage costs are within the range of published resources such as WoodMackenzie and NIPSCO and at the very top end of the EPRI range. (Tr. Vol. 5, p. 1390.15.) Witness Kalemba also explained that the battery design that the Companies included in the 2020 IRPs was designed to be flexible, reliable, and safe to operate in order to meet both the current and potential operating requirements that may be placed on battery storage. (Tr. Vol. 5, p.1390.16.) While Witness Kalemba accepted that at least some of the published battery costs are likely to meet the Companies' requirements, many would not be robust enough to meet the needs of the Companies' system and some may not even meet the basic requirements to interconnect to the system. (*Id.*) In particular, Witness Kalemba testified that published industry cost projections, such as those from NREL relied upon by Witness Lucas, do not account for recent updates to fire safety standards released in 2020. (Tr. Vol. 5, p. 1476-1479.) With regard to the projected decline in battery storage costs, Witness Kalemba explained that the Companies' projected cost *declines* are very similar to the NREL ATB advanced case, where the Companies' cost projections decline 34% and the NREL ATB advanced case declines 37%. (Tr. Vol. 5, p. 1390.19.)

In addition, Witness Kalemba noted that the NREL 2020 Battery Report highlighted the difficulty of using published resources to establish battery costs for long term planning purposes given their use case-specific nature. (Tr. Vol. 5, p. 1390.15, *quoting* NREL 2020 Battery Storage 2020 Update, at 7 (noting that "[t]here are a number of challenges inherent in developing cost and performance projections based on published values[,]" including that (1) "the definition of published values is not always clear[;]" (2) "many of the published values compare their published projection against projections produced by others [in a way that might] artificially bias . . . results[;]" and (3) a "limited dataset" and "rapidly changing costs" make it difficult to evaluate projections).)

With regard to "solar plus storage" cost projections, CCEBA Witness Lucas argued that the Companies' approach to developing costs for solar plus storage was inappropriate because it differed from the Companies' approach to developing costs for standalone storage. (Tr. Vol. 2, p. 501.45-46.) Witness Kalemba explained that it is appropriate for the Companies to use two different methodologies for these technologies because the useful life of each asset is different. In the IRPs, the Companies assume solar assets have 30-year lives, while battery storage assets have 15-year lives. (Tr. Vol. 5, p. 1390.23.) Over the life of a battery, the energy capacity of the battery cells degrade, and if nothing is done to mitigate this degradation, the battery will hold significantly less usable energy at year 15 than it did during year one. (*Id.*)

For standalone storage, the Companies account for degradation by "augmenting" the battery with additional battery cells at regular intervals to maintain the usable energy of the battery. For solar plus storage, the Companies account for degradation through "overbuild" of the battery so that as the battery cells degrade, the amount of usable energy in year 15 is the same as in year one. (*Id.*) Witness Kalemba explained that while it may be appropriate to augment a battery over the 15-year life, there is risk that as battery technologies rapidly evolve, the ability to cost-effectively and reliably augment the battery may be challenged. (*Id.*) Witness Kalemba explained that such risks would only increase if augmentation were assumed for maintaining a battery's energy capacity over a 30-year period. For these reasons, the Companies intentionally chose different approaches to mitigate degradation between standalone storage and storage paired with solar.

Modeling Two-hour Batteries

Witness Lucas also recommended that the Companies update their model to select up to 1,500 MW of two-hour batteries in DEP and up to 1,000 MW of two-hour batteries in DEC. He argued that the Companies should have included two-hour batteries as an available resource along with longer duration batteries as they could serve a meaningful role in serving peak load during winter mornings. (Tr. Vol. 2, p. 498.)

DEC/DEP Witnesses Wintermantel and Kalemba explained that Witness Lucas's recommendation was not reasonable. Witness Wintermantel explained that the Storage ELCC Study evaluated the capacity value of two-, four-, and six-hour batteries with varying amounts of battery capacity as well as two different solar penetration levels for both DEC and DEP. (Tr. Vol 2, p. 383.) This approach provided the companies with a wide range of results to see how the capacity value would change based on different assumptions. (*Id.*) The Storage ELCC Study showed that four- and six-hour batteries had significant capacity value for both the DEC and DEP systems, but the two-hour batteries provided less capacity value. (*Id.*)

Witness Kalemba explained that while the Storage ELCC Study did identify that 2-hour battery storage could potentially provide nearly 90% capacity value for the first increments of storage, that value quickly drops as incremental storage is added. (Tr. Vol. 2, p. 1390.37.) Witness Kalemba explained that given the potential for demand side resources to satisfy the incremental demand over shorter periods of time, the Companies are only considering four-hour storage, or longer, for capacity value in their IRPs. (Tr. Vol. 5, p. 1039.40.)

Witness Roberts also raised concerns with Witness Lucas's recommendation that significant solar and two-hour batteries could replace dispatchable natural gas generation and provide meaningful capacity to the DEC and DEP systems. He explained that this alternative resource-planning recommendation would fundamentally change the Companies' generating fleets and introduce operational challenges and reliability risks that would need to be studied and planned for to ensure that power supply reliability and NERC compliance can be maintained. (Tr. Vol. 4, p. 1052.14.)

Solar and Battery Storage Modeling

CCEBA Witness Olson argued that the Companies did not model solar and storage in a manner that accounts for synergies between them. (Tr. Vol. 2, p. 485-6.) According to Witness Olson, by failing to co-optimize solar and storage resources in a single step—i.e., considering the value of renewable energy in a vacuum, separate and apart from storage capacity—the Companies devalued renewable options. (Tr. Vol. X, pp. 485.13 - 485.14) Witness Olson argued that the Storage ELCC Study should use an ELCC surface to recognize the diversity benefit of solar and storage being added together. (Tr. Vol. 2, p. 485.6.)

In response, Witnesses Snider, Kalemba, and Wintermantel acknowledged that the Companies employed a sequential, rather than single step, approach to optimization given the limitations of the portfolio optimization screening tools, but explained that the approach did not have the effect of devaluing solar. (Tr. Vol. 2, p. 389.44; Tr. Vol. 5, pp. 1390.42 - 1390.43; Tr. Vol. 6, p. 1586.132 – 1586.133.) In particular, Witness Wintermantel explained that the Storage ELCC Study takes full advantage of the synergies between solar and storage because significant solar is already in the study, yielding synergistic value to batteries in the study. (Tr. Vol. 2, p. 385.) Witness Kalemba explained that when the Companies evaluated storage on the DEC and DEP systems in the IRPs, the amount of solar on those systems was significant and already in the range of the amount of solar included in the Storage ELCC Study (Tr. Vol. 5, p. 1390.42). In addition, Witness Snider explained that batteries were robustly evaluated in the Companies' production cost model. (Tr. Vol. 6, p. 1586.132.) As part of the modeling, the Companies replaced CTs that were economically selected in the portfolio development in the capacity expansion model with the equivalent firm amount of battery capacity, based on storage capacity value results from the Storage ELCC Study. (*Id.*) This additional step was taken in an effort to fairly evaluate the value of storage with the model that is better suited for storage valuation. (Tr. Vol. 6, p. 1586.133.) Witness Snider also explained that storage benefits can best be measured in production cost models that examine hour-by-hour dispatch of the system and identify periods when storage should charge and discharge to lower the overall cost of the system. (*Id.*) He explained that these nuances of chronology and high and low load hours are muted in the capacity expansion model, as the hour aggregation and simplification of the model is used to speed up processing time. Accordingly, the robust approach used by the Companies ensured batteries were given a fair evaluation in economic selection in the base case portfolios. (*Id.*)

Single Axis Tracking Solar versus Fixed Tilt Solar

Witness Lucas criticized the Companies' assumption that nearly 100% of solar installed in the Carolinas is Fixed-Tilt solar and that future solar was assumed to be a 60/40 blend of Single-Axis Tracking / Fixed-Tilt solar technologies. (Tr. Vol. 2, p. 501.57-58.) He argues that these assumptions "produce a model that relies too heavily on fixed tilt systems and does not reward the multiple benefits of single-axis tracking systems that are being deployed in the market." (Tr. Vol. 2, p. 501.60.).

In response, Witness Kalemba noted that nearly all of the current PURPA solar facilities that are operational on the Companies' systems today are Fixed-Tilt, as opposed to Single-Axis Tracking (Tr. Vol. 5, p. 1390.32.) Witness Kalemba also explained that the Companies' assumptions about future solar is based on the information available at the time the IRPs were developed. Witness Kalemba testified that at that time, the results from the competitive procurement of renewable energy or "CPRE" Tranche 1 showed that approximately 60% of final standalone solar projects were Single-Axis Tracking projects, while the remaining 40% of projects were Fixed-Tilt. (Tr. Vol. 5, p. 1390.33.) Subsequently, the results of CPRE Tranche 2 became known and 100% of solar projects were designed as Single-Axis Tracking. (*Id.*) In their respective 2021 IRP Updates, the Companies have committed to assume all new solar will reflect 100% Single-Axis Tracking, consistent with the new information received from CPRE Tranche 2. (*Id.*)

Interconnection Limits

Witness Lucas criticized the Companies for imposing a 500 MW interconnection limit on the amount of solar that can be interconnected to the system each year. (Tr. Vol. 2, pp. 501.60 – 501.61.) Witness Lucas recommends the Companies' amend the interconnection limits to 1,500 MW between 2021 and 2029 and 1,800 MW in 2030 and beyond. (Tr. Vol. 7, p. 1911.19.) Witness

Kalemba explained that there are "real world" timing and physical constraints on the amount of new generation that can be connected to the Companies' systems each year. (Tr. Vol. 5, p. 1390.35.) First, the process through which new requests to interconnect to the Companies' systems and the studies that evaluate the potential interconnection are time consuming and complex. In addition, significant portions of the DEC and DEP transmission systems are identified as "constrained" meaning that significant transmission upgrades are required in order to add additional generation. (Tr. Vol. 5, pp. 1390.35 – 1390.36.) Once the interconnection study process is complete, the construction of the network upgrades is dependent on a number of factors, including: other work taking place on the transmission system (i.e. customer connections, maintenance, other interconnection construction and general transmission projects), generator outages which can change power flows on the system, and projected energy demand on the system. (Tr. Vol. 5, p. 1390.36.)

Witness Kalemba further explained that the 500 MW limit was based on review of the average amount of MW interconnected to the Companies' systems in recent years. From 2014 through 2019, the Companies interconnected an average of 527 MW each year. (*Id.*) While the Companies did interconnect 744 MW in 2017, only 556 MW were interconnected in 2018 and 267 MW were interconnected in 2019. He also pointed out that that the Companies interconnected only 320 MW in 2020. Based on this analysis and recognizing the saturation of solar on the DEC and DEP systems, Witness Kalemba explained that the Companies 500 MW limit is a reasonable projection of what is feasible to interconnect to the systems each year throughout the planning period. (*Id.*)

Federal Investment Tax Credit

CCEBA Witness Lucas discussed the December 2020 extension of the federal investment tax credit ("ITC") that has been and, now, will continue to be available to solar facilities, suggesting that the Companies should be required to update their capital costs through a modified 2020 IRP to reflect the significant change in policy. (Tr. Vol. 2, p. 501.38.) In response, Witness Kalemba explained that the Companies plan to update the modeling of their capital costs to account for this change going forward, but state that it would not be reasonable to issue entirely new IRPs to incorporate this change in policy that occurred after the 2020 IRPs were filed. (Tr. Vol. 5, pp. 1382, 1390.7.) As Witness Kalemba explained, the IRP process is intended to present information that is accurate at a specific point in time when such inputs and assumptions were developed. (Tr. Vol. 5, p. 1390.7.) The 2020 IRPs are based on inputs and assumptions generally fixed in late spring and summer months of 2020 leading up to the September submittal of the IRP. By functional necessity, the inputs and assumptions represent information that was available at that point in time prior to the time of filing. (*Id.*) As explained by DEC/DEP Witness Snider, IRP development is a nearly continuous process, and as statutory, regulatory and policy developments continue to occur, these new developments will inform future IRPs. (Tr. Vol. 6, p. 1586.47.) Witness Kalemba argues that it would be impossible to revise the IRPs upon each policy change or new information that is released after the IRPs are completed. (Tr. Vol. 5, p. 1390.7.) Accordingly, Witness Kalemba explained that the ITC extension is being incorporated into the assumptions used in the IRP Update, which will be filed with the Commission in September 2021. (Tr. Vol. 5, p. 1390.8.)

Solar PPA Resource Option

ORS recommended the Companies add a generic solar PPA resource option in its modeling that reflects the kind of PPA price that may be available in the market. (H. Ex. 24, DEC ORS

Report, p. 10; DEP ORS Report, p. 10.). ORS suggested using a 20-year PPA based on the pricing information available from the Companies' North Carolina Competitive Procurement of Renewable Energy Program ("NC CPRE Program"). CCEBA Witness Lucas agreed with this recommendation. (Tr. Vol. 7, p. 1911.43-44.) DEC/DEP Witness Snider expressed concerns with adding a PPA option into the model specifically for solar, where no other PPA option is included for other generation technologies. (Tr. Vol. 6, p. 1586.122.) Witness Snider also testified that it would be inappropriate for the model to evaluate a 20-year solar PPA against a 30-year solar asset, and that such disparities would result in an "apples to oranges" comparison. (Tr. Vol. 6, pp. 1586.122 – 1586.123, p. 1687.) At the hearing, in an attempt to "find middle ground" Witness Snider testified that it would be reasonable for the Companies to run sensitivities on certain portfolios to evaluate whether or how much solar would be cost effective at various price sensitivities. (Tr. Vol. 6, p. 1680-81.) With regard to using price information from the NC CPRE Program, Mr. Snider testified that there was no guarantee that PPAs at the price selected for the NC CPRE Program would be available again in the market, and as a result, the sensitivity analysis of the solar PPA option would be based on an assumption that a market would exist at various points in time for those prices. (Tr. Vol. 6, p. 1688, 1694.)

Commission Conclusions

Act 62 requires the Companies to evaluate low, medium, and high cases for the adoption of renewable energy for the purpose of fairly evaluating the potential range of demand-side, supply-side, storage, and other technologies available to meet the utility's service obligations. (S.C. Code Ann. § 58-37-40(B)(1)(e).) Considering the testimony and exhibits of DEC/DEP Witnesses Kalemba, Wintermantel, and Snider, the Commission is persuaded that the Companies have conducted a robust evaluation of the potential to interconnect new renewable energy into their systems and have structured the six portfolios in the 2020 IRPs to rely on a mix of medium and high case adoption of renewable technologies, which the Commission finds meets their obligations under Act 62. In addition, the Commission finds credible the testimony of Witnesses Kalemba and Wintermantel explaining the rationale behind the inputs, assumptions and modeling that the Companies used to evaluate the appropriate implementation of renewable energy. With regard to solar and battery storage cost projections, the Commission finds that the Companies' projected costs are appropriate and are reasonably within the realm of other industry cost projections. The Commission recognizes that the Companies' low-cost solar sensitivities already illustrate the impact of lowering the Companies' solar costs and that it is unnecessary for the Companies' to modify their 2020 IRPs to evaluate solar at a lower cost. Additionally, the Companies' agreement to evaluate solar PPA options at various price sensitivities will provide additional cost sensitivities for evaluation in future IRPs. We find that it is appropriate for the Companies to update their solar costs to incorporate the recently-extended Federal ITC in the 2021 IRP Update. As Witnesses Kalemba and Snider explained, IRPs present the Companies' plans from the lens of a snapshot in time, incorporating technology and statutory and regulatory requirements as they exist in that moment. Requiring the Companies to update as-filed IRPs in real-time with the announcement of each new legal shift or technological advancement would create an overly burdensome process subject to endless delays and offering little benefit to the Companies or customers.

As it relates to battery storage cost projections, we understand that this is an area in which technology and cost projections are rapidly evolving. We find that the Companies have sufficiently justified the reasonableness of their battery storage cost projections, which represent the specific costs of batteries that could be used on the Companies' systems. We understand and appreciate the Companies' commitment to safety in designing the specific battery that is appropriate for their system and their customers, and we reject CCEBA's argument that projecting costs of a battery that is compliant with operational and safety standards constitutes improper utility "gold plating." Accordingly, the Commission finds that the Companies' cost projections for renewable energy and battery storage technologies are reasonable and comply with the requirements of Act 62.

With regard to solar operational assumptions, the Commission finds reasonable the Companies' decision to limit the volume of new solar resources that can be interconnected in a single year to 500 MW. As Witness Kalemba explained, this limit was not arbitrarily selected, but based upon historical data and DEC's and DEP's recent actual experience with the temporal and physical constraints of the interconnection process, including both the study process and the construction process needed to accomplish the interconnection. In contrast, the proposed volumes of new solar interconnections proposed by Witness Lucas has no connection to the actual experiences of the Companies. Additionally, we agree that the Companies' assumptions related to Single-Axis Tracking and Fixed-Tilt solar configurations appropriate. These assumptions are based on information actually known by the Companies at the time the 2020 IRPs were developed and the Companies will continue to update those assumptions as the industry evolves and information available to the Companies changes.

The Commission finds that the Companies' capacity expansion modeling appropriately accounts for the synergies between solar and storage. We are persuaded by the testimony of Witnesses Snider and Wintermantel that explain how the Companies' capacity expansion modeling and the Storage ELCC Study ensure that synergistic values are achieved and that such studies and modeling in no way have the effect of devaluing solar or storage. We also agree that it is reasonable for the Companies' to refrain from modeling two-hour batteries, given their limited value in comparison to the four-hour and six-hour batteries included in the Companies' modeling.

Finally, with regard to the solar PPA option, we appreciate the Companies' willingness to "find middle ground" on this disputed issue. The Commission finds reasonable Witness Snider's proposal for the Companies to evaluate various solar PPA option price sensitivities in the 2021 IRP Update. The Commission understands that modeling a PPA option only for one specific resource type could be interpreted as unfairly treating one resource type over another, but also understands the intervenors' desire for the Companies to incorporate these alternative options given the interest in solar procurement in the marketplace of late. The Commission also understands that there are no guarantees that solar PPAs would be available in the market at any of the prices the Companies may include and that such information would be "hypothetical" only. This does not seem unreasonable, however, given then that the IRPs are based, in part, on assumptions and/or conditions that may or may not materialize in the future.

b. *Current and Foreseeable Environmental Regulations*

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 20

Summary of the Evidence

The evidence in support of these findings of fact are found in the Companies' 2020 IRPs, pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

Vote Solar Witness Fitch argues in his direct testimony that the Commission should reject the Companies' IRPs because they do not adequately assess or manage climate-related risks. (Tr. Vol. 3, pp. 736.39-736.40.) Witness Fitch recommends that the Commission reject the long-term portion of the Companies' IRPs and direct the Companies to include the following in future IRPs: (1) a systematic assessment of climate-related risks; (2) adoption of more strategies to manage climate-related risks; (3) explicit consideration of the Companies' anticipated zero-carbon transition; and (4) evaluation of its Plans that fairly considers long-term costs. (Tr. Vol. 3, pp. 736.8, 736.100-736.102.) Similarly, CCEBA Witness Olson opines that technological and cost realities associated with climate policy and climate change should be incorporated into the Companies' IRP process. (Tr. Vol. 2, p. 485.7; H. Ex. 15, p. 34.)

In rebuttal testimony, Witness Santoianni testifies that Vote Solar asks for a climate risk assessment that includes elements beyond the scope of an IRP, ignores commitments made by the Companies outside of the IRP process, and is already addressed in Duke Energy's Climate Report and other disclosures. (Tr. Vol. 5, p. 1536.12.)

Witness Santoianni explains that Witness Fitch misunderstands the purpose of the IRPs, and that he implies that the Companies' 15-year IRPs should morph into a climate risk assessment, rather than their regulatory purpose to serve as a long-range resource plan developed to maintain system reliability for customers over the next 15 years. She noted that the IRPs must balance resource adequacy and capacity to serve anticipated peak electrical load with affordability and compliance with applicable state and federal environmental regulations. (Tr. Vol. 5, p. 1536.7.) The IRPs are updated annually, as technologies evolve, fuel and technology costs change, load forecasts adjust, new laws are enacted, and regulations are promulgated. As such, the IRPs represent a snapshot in time, versus a vehicle to get the Commission to set and codify climate policy. (Tr. Vol. 5, p. 1536.8.)

Witness Santoianni states that Witness Fitch's recommendations also confuse the roles of regulated utilities, legislators and environmental regulators and attempts to place the burden of policy setting on the Companies, by asserting that the Companies should assess additional carbon pricing scenarios to address the social costs of climate change in the IRPs. (Tr. Vol. 5, p. 1536.7.) The Companies are not policymakers and, while their management may set aspirational climate goals, they do not and cannot set climate policy. By asking for the Companies to study policies to achieve net zero by 2050 within the IRPs, Witness Fitch essentially asks the Commission to issue a mandate that sets a climate policy and brings climate policy studies into the scope of the IRPs. (Tr. Vol. 5, p. 1536.3.) Witness Santoianni clarifies that the Companies' responsibility is to provide safe, reliable and affordable energy to its customers and comply with and to follow the suite of health and safety regulations that are established by state and federal regulators. State and federal legislation and regulation drive the incorporation of environmental attributes and risk into the cost of any particular resource, and the Companies must account for the costs associated with state and federal laws and promulgated regulations into the IRPs. (Tr. Vol. 5, p. 1536.9.)

Additionally, Witness Santoianni testifies that in suggesting that the Companies' IRPs ignore climate risk, Witness Fitch ignores the fact that the carbon sensitivities included in the 2020 IRPs adequately recognize the potential for shifting legal and regulatory requirements around carbon policy and climate change. However, because the Companies cannot set policy, the carbon pricing in the IRPs is used as a proxy for future policies, in order to understand how resource planning may respond to future regulatory changes. She states that it is neither appropriate nor a prudent use of resources and customers' dollars to conduct an analysis of carbon prices and how that may affect climate risk in the future. (Tr. Vol. 5, p. 1536.9.)

Similarly, Witness Snider's rebuttal testimony clarifies that the Companies incorporate future carbon regulation and climate risk in the IRP process in a variety of ways, where applicable, in relation to the factors identified in Act 62. With input from stakeholders, the IRP explores the opportunities and challenges over a range of options for achieving varying trajectories of carbon emission reduction. He states that the 2020 IRP highlights six possible portfolios within the 15-year planning horizon. These portfolios explore the most economic and earliest practicable paths for coal retirement; acceleration of renewable technologies including solar, onshore and offshore wind; greater integration of battery and pumped-hydro energy storage; expanded energy efficiency and demand response and deployment of new zero-emitting load following resources such as small modular reactors. All pathways included in the 2020 IRP keep Duke Energy on a trajectory to meet its longer-term carbon reduction goals over the 15-year planning horizon considered in the 2020 IRPs. (Tr. Vol. 6, pp. 1586.135-36.)

Witness Snider also explains that Witness Fitch's analysis is narrowly focused and fails to weigh affordability, reliability, and the risk that certain technologies may result in higher costs to customers against the purported benefits of his clean energy proposal as the Companies are required to do under Act 62. He states that the Companies take seriously their responsibility to continue to provide reliable, affordable, and increasingly clean energy to their customers in South Carolina, an obligation that Witness Fitch and Vote Solar do not share. (Tr. Vol. 6, pp. 1586.139.)

Witness Santoianni also addresses Witness Fitch's implication that because the IRPs only forecast the Companies' resource plans over the next 15 years, the resource plans are somehow inconsistent with Duke Energy's 2050 climate goal. She explains that Witness Fitch ignores that all of the portfolios in the IRPs place the Companies on a trajectory for reaching net zero emissions by 2050. His testimony also suggests the time horizon for the IRPs to be 30 years, rather than 15 years, the time frame provided in the South Carolina IRP statute. Witness Santoianni explains that it is not appropriate for the IRPs to speculate what policies may look like in 2050. It is outside the timeframe of the plan, and any consideration of costs or available technologies would be highly speculative and subject to significant uncertainty. Requiring the IRPs to look out through 2050 could grossly increase the cost and complexities of the IRP process—ultimately paid for by customers—with no real benefit, particularly given that the Companies regularly file comprehensive IRPs and updates annually between comprehensive filings. (Tr. pp. 1536.7-1536.8.) At the hearing, Witness Santoianni also noted that as policies evolve, for instance with a national climate policy or climate regulation, then the Companies would incorporate that and then be able to address that specifically in the IRPs. (Tr. Vol. 5, p. 1549)

Witness Santoianni also notes that Witness Fitch ignores the Companies' actions outside of IRP process that are informed by climate risk. She reports that Duke Energy publishes a climate report based on the reporting framework from the Task Force on Climate-Related Financial Disclosures ("TCFD"), which is considered the standard for climate disclosures. The climate report is published outside of the IRP process, and details numerous actions that Duke Energy takes to address physical, financial, economic, regulatory and reputational risks – the same risk categories and framework that Witness Fitch believes should be addressed within the IRP process. Witness Fitch's specific acknowledgement that the TCFD framework in Duke Energy's climate report provides "an accessible template" for climate-related risk information undercuts his contention that more climate analysis should be ordered as part of the IRP process. (Tr. Vol. 5, pp. 1536.4, 1536.11.)

Finally, Witness Santoianni notes that the type of climate risk analysis that Witness Fitch is asking the Commission to mandate in the IRPs is redundant with a study that is the product of a settlement agreement entered into between Vote Solar and the Companies in North Carolina. As part of that settlement, the Companies have agreed to undertake a climate resiliency study in a rate case docket before the NCUC. (Tr. Vol. 5, pp. 1536.4-1536.5.) That agreed upon study is not part of an IRP proceeding, will encompass the information Witness Fitch requests in his testimony, and can be used to inform federal and state policymakers who will ultimately determine utilities' requirements with respect to climate change and risk. Witness Santoianni states that it would be inappropriate to capture the analysis and results of such a study within the silo of the IRP process, when it should be part of a much larger conversation about climate resiliency. She explains that, for practicality and for costs' sake, the IRPs should not become an open-ended process that is "all things to all people." (*Id.)* The IRPs are planning documents rooted in the Companies' plans to meet load and operate reliably and efficiently under today's legal and regulatory requirements. To overwhelm the IRP process with perpetual "what if" possibilities would obscure this fundamental purpose, creating ever-moving goal posts and unnecessarily increasing costs for customers. (*Id.*)

In surrebuttal, Witness Fitch argues in favor of a broader purpose and scope of integrated resource planning in South Carolina and contends that the Commission can and should consider the impact of climate-related risks in determining whether the IRPs "are the most reasonable and prudent for South Carolina ratepayers." (Tr. Vol. 3, pp. 742.15-742.16.) He states that while the specific shape that federal policy will take is not yet clear, this should not prevent the Companies or the Commission from considering the implications of the clean energy transition for the Companies and South Carolina ratepayers. (Tr. Vol. 3, pp. 742.25.)

Discussion and Conclusions

In consideration of the foregoing evidence, the Commission concludes that the Companies' 2020 IRPs appropriately and reasonably recognize and plan for existing and potential future environmental regulations that could impact resource planning in the near future, and that this approach meets the requirements of Act 62. CCEBA's and Vote Solar's recommendations for the IRPs to incorporate additional climate change analysis are inappropriate, as they go beyond the scope of an IRP proceeding, ignore appropriate consideration of climate change that the Companies are already doing both within and outside of the IRP context, and would result in the

Commission inappropriately directing the Companies to engage in climate change policy-making that is the purview of state and federal legislatures and regulators, and should therefore be rejected.

S.C. Code Ann. § 58-37-40(B)(1)(e)-(e)(iii) provides that a utility's IRP shall include, among other things, "several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations. Such portfolios and evaluations must include an evaluation of low, medium, and high cases for the adoption of renewable energy and cogeneration, energy efficiency, and demand response measures, including consideration of the following … sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks," in addition to customer EE and DSM programs and facility retirement assumptions. As detailed by Witnesses Santoianni and Snider, the Companies' IRPs appropriately recognize and plan for environmental regulations that exist today as well as analyze foreseeable potential regulations on carbon emissions that could impact resource planning in the near future. This approach meets the requirements of § 58-37-40(B)(1)(e)(iii) to conduct sensitivity analyses related to uncertainties or risks including environmental regulations. Vote Solar and CCEBA have not presented any evidence that the Companies have not satisfied these requirements.

Vote Solar's and CCEBA's recommendations that the Commission direct the Companies to incorporate climate change study into the IRPs are inappropriate as they fall outside the scope of an IRP. First, while Act 62 requires the Commission to consider and weigh "other foreseeable conditions that the commission determines to be for the public interest[,]" S.C. Code Ann. § 58-37-40(g), setting climate policy lies well outside such a consideration and, in any event, the Companies' IRPs reasonably and appropriately consider climate change-related regulations in the course of meeting the requirements of Act 62 as addressed above. More broadly, it is for federal and state legislatures and regulators, and not the Companies, to determine climate policy. The Commission recognizes that part of the Companies' responsibility to provide safe, reliable and affordable energy to its customers requires the Companies to account in the IRPs for the costs associated with state and federal laws and promulgated regulations. The Commission concludes that the Companies have met this requirement and agrees that the IRP proceedings should not be permitted to become overwhelmed as "catch-all proceeding" for intervenors' individual priorities that fall outside the discrete requirements of Act 62.

Finally, Vote Solar's and CCEBA's testimonies mention but discount the numerous ways in which the Companies already factor in climate change, to the extent appropriate, to their IRPs as discussed by the Companies' witnesses. In addition, intervenors' recommendations ignore the significant effort the Companies make to evaluate such risks outside of the IRP context, through the Companies' 2020 Climate Report and future climate-related studies that Witness Santoianni testified were underway. Taken together with their over-reach as discussed above, these parties' failure to acknowledge the work the Companies are doing within and outside of the IRP context to consider climate change and risk undercuts the credibility and persuasiveness of their testimony.

In sum, the Commission finds that the 2020 IRPs reasonably meet the requirements of Act 62 to both consider existing environmental regulations and to plan for requirements, risks and policies that foreseeably may be mandated in the future. Nothing further is required by Act 62.

c. *EE/DSM*

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 21-22

Summary of the Evidence

The evidence in support of these findings of fact are found in the Companies' 2020 IRPs, pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

Duke Witness Bak provided testimony regarding the IRPs' evaluations of EE/DSM programs and measures. Witness Bak testified that, for IRP purposes, EE-based demand and energy savings are treated as a reduction to the load forecast, and DSM programs—also sometimes referred to as demand response programs—are treated by the IRPs as resource options that can be dispatched in lieu of additional traditional generating assets to meet system capacity needs during periods of peak demand. (Tr. Vol. 1, p. 258.5.) Witness Bak also testified that the Companies' EE/DSM team meets with the EE/DSM Collaborative, an advisory group of interested stakeholders who provide insight and input to DEC and DEP as related to EE/DSM programs. (Tr. Vol. 1, p. 258.7.)

According to Witness Bak's testimony, the Companies commissioned EE/DSM Market Potential Studies to obtain estimates of the technical, economic and achievable potential for EE/DSM savings within the DEC and DEP service areas, the final report for which was prepared by Nexant Inc. ("Nexant"). The Companies found the Market Potential Studies to be a reasonable assessment of the potential for energy savings, and the Companies relied upon the studies in the development of their IRPs. (Tr. Vol. 1, p. 258.10.) Nexant applied the Total Resource Cost ("TRC") cost-effectiveness test to evaluate potential EE/DSM savings, but also included a sensitivity to estimate the potential savings based on the Utility Cost Test ("UCT"), which resulted in an increase to the estimated potential savings. As explained in Witness Bak's testimony, the Commission authorized the use of the UCT in January 2021—through Order No. 2021-32, Docket No. 2013-298-E (Jan. 15, 2021) and Order No 2021-33, Docket No. 2015-163-E (Jan. 15, 2021)—for purposes of evaluating programs to be offered to the Companies' customers. (Tr. Vol. 4, pp. 1000.13-1.4.) According to Witness Bak's testimony, the EE/DSM savings contained in the IRPs were projected by blending the Companies' respective five-year program planning forecast into the long-term achievable potential projections from the Market Potential Studies. (Tr. Vol. 1, p. 258.11.)

According to Witness Bak, the Companies prepared three sets of projections consistent with Act 62: (1) a Base or medium EE Portfolio savings projection based on the Companies' respective five-year program plans for 2020-2024, which was blended together with the Base Scenario from the Market Potential Studies for 2025-2035; (2) a High EE Portfolio savings projection also based on an adjusted five-year program plan for 2020-2024 and blended with the Enhanced and Avoided Energy Cost Sensitivity Scenarios contained in the Market Potential Studies for years 2025-2035; and (3) a Low EE Portfolio savings projection developed by applying a reduction factor across all measures in the Base EE Portfolio forecast as a way to forecast lower than expected adoption of all measures. (Tr. Vol. 1, p. 258.11.) This methodology is described on pages 35-36 of the DEC and DEP IRPs.

ORS found that the Companies complied with Act 62 as related to EE/DSM "by developing six (6) specific Portfolios in which it evaluated a range of demand-side, supply-side, storage and other technologies and services that could be relied on to meet its obligations." (H. Ex. 24, pp. 18, 121.) As stated in the ORS Reports, "[t]he Commission approved the Company's most recent five-year DSM and EE Program plan in its order on January 15, 2021, which has a goal of achieving energy savings of 1% of annual retail sales." (H. Ex., pp. 48, 151.) The only recommendation ORS had with respect to the Companies' EE/DSM evaluations was that the Company provide additional detail regarding its low EE/DSM scenario. (H. Ex., pp. 48, 151.)

Environmental Parties' Witness Grevatt asserted that there were certain limitations to the EE/DSM Market Potential Studies relied upon by the Companies, arguing that the Studies should have relied upon Energy Information Administration data for commercial and residential end-uses, failed to account for technology improvements, only accounted for potential savings achievable from measures included in the Companies portfolios, and relied upon the TRC test rather than the UCT. Witness Grevatt recommended that the Companies rely upon the UCT rather than TRC, add in savings from unspecified emerging technologies, and use end-use data from the Energy Information Administration. (Tr. Vol. 3, p. 667.6.) During the hearing, the Commission took judicial notice of Order Nos. 2021-32 and 2021-33—order issued in January 2021 which approved a 1% EE savings goal for the Companies until 2026, and which approved a change from the TRC to the UCT for new programs and program modifications filed on or after January 1, 2021. Order No. 2021-32 at 4-5, Docket No. 2013-298-E (Jan. 15, 2021); Order No. 2021-33 at 5, Docket No. 2015-163-E (Jan. 15, 2021).

The Companies presented the rebuttal testimony of Witnesses Bak and Herndon. Witness Bak explained that it is important that the EE/DSM evaluations be accurate because of their connection to system planning and reliability. Witness Bak stated that inflating these estimates will compromise the accuracy and soundness of the IRPs and thus the reliability of the system. (Tr. Vol. 4, pp. 1213.2-3.) Mr. Bak pointed out that, when asked in discovery about emerging technologies that could be included in the savings analysis, no specific measures applicable to the Companies' service territories was identified by the other parties. Witness Bak also explained that tightening efficiency codes and standards narrow the incremental savings the Companies can achieve. (Tr. Vol. 4, pp. 1213.9-10.) Witness Bak pointed out that of the nineteen measures Mr. Grevatt argues were omitted from the Market Potential Studies, eighteen actually were accounted for in the Market Potential Studies, and the one measure that was not accounted for is a gas measure that has no application in these proceedings. (Tr. Vol. 4, pp. 1213.10-12.)

Mr. Bak testified that, like the IRP, the Market Potential Studies are a "snapshot in time" and should not be revised for events occurring after its completion, but that future Market Potential Studies would account for any relevant updates. (Tr. Vol. 4, pp. 1213.16-17.) Witness Bak agreed with ORS Witness Sandonato's recommendation that future IRPs include a more precise development of the low EE/DSM scenario. Mr. Bak explained that there are factors that could lead to a low EE/DSM outcome, including new efficiency codes and standards implemented by the new federal administration, as well as shifting economic conditions or changes in the market. (Tr. Vol. 4, p. 1213.19-20.)

Witness Herndon explained that EE/DSM Market Potential Studies must provide technically sound estimates of future EE and DSM program opportunities by relying upon available data for a given jurisdiction, and a defined analytical procedure. (Tr. Vol. 4, p. 1000.5.) Mr. Herndon took issue with the assertion that the savings evaluation should include unnamed "emerging technologies" in addition to the comprehensive list of measures already included in the studies. Mr. Herndon also took issue with Mr. Grevatt's recommendation that the Market Potential Studies should account for unspecified "technology improvements" and not take into account changes in efficiency codes and standards. (Tr. Vol. 4, p. 1000.5-.9.) Mr. Herndon disagreed that generic data from the Energy Information Administration should be used instead of data that more closely aligns with the Companies' customers and service territories. As related to the TRC test versus the UCT, Mr. Herndon explained that the Companies were not authorized by the Commission to use the UCT for screening measures until January 2021, well after the Market Potential Studies was completed and the IRPs were filed. (Tr. Vol. 4, p. 1000.13-14).

Witness Herndon testified that, in order to develop an accurate understanding of a utility's potential for energy efficiency and demand-side management savings, a market potential study must be factually grounded, and utilize valid, quantifiable inputs, ideally with data from the utility's actual customer base and service territory. Mr. Herndon testified that Nexant conducted the Companies' Market Potential Studies with these characteristics and that Mr. Grevatt's recommendations are not supported by valid technical data that would improve the quality or accuracy of the studies. (Tr. Vol. 4, p. 1000.16-17.)

In his surrebuttal testimony, Mr. Grevatt changed his recommendations; instead of recommending that changes be made to the Market Potential Studies and IRPs, he recommended that the Companies conduct an assessment representing 1% EE savings. Mr. Grevatt also recommended that the Companies model additional levels of savings at 1.25%, 1.5%, 1.75%, and 2.0%. (Tr. Vol. 3, p. 673.25.) Mr. Grevatt recognized in his surrebuttal testimony that most of the measures he had previously identified as being omitted from the Market Potential Studies were actually included in the studies. (Tr. Vol. 3, p. 673.22-23.) Further, Mr. Grevatt conceded during the hearing that, while there was disagreement as to whether four measures were included or not included in the savings accounted for in the Market Potential Studies, the studies had accounted for savings from 329 distinct energy efficiency measures, and 8,994 measure permutations, making this dispute about the four measures insignificant. (Tr. Vol. 3, p. 676.) Additionally, while Mr. Grevatt recommended that the Companies assume savings levels achieved by utilities in other states without an analysis of what accounted for those savings, he conceded during the hearing that technical EE manuals he relied upon from Michigan and Illinois both required that the achievable savings be climate- and territory-specific, in contrast to simply assigning an EE savings level amount based on another jurisdiction's savings or using generic Energy Information Administration end-use data instead of data specific to the Companies' customers. (Tr. Vol. 3, pp. 677-680.) Likewise, Mr. Grevatt agreed that the climates of Massachusetts and Rhode Island—

the states used in Ms. Wilson's Synapse Report as EE references—are distinct from that of South Carolina, a factor that, according to the technical EE manuals relied upon by Mr. Grevatt, distinguishes the types of EE programs and the amount of savings estimates between utilities located in different areas. (Tr. Vol. 3, pp. 681, 677-79.)

Mr. Grevatt also acknowledged during the hearing that energy efficiency standards promulgated or issued by the federal government can take away from or erode the savings achievable from a utility's energy efficiency program. (Tr. Vol. 3, p. 681.) Mr. Grevatt specifically acknowledged during the hearing that his client, the National Resources Defense Council, was party to a lawsuit filed against the U.S. Department of Energy to compel the update of appliance energy efficiency standards, that President Biden had issued Executive Order 13990, and that the Acting Secretary of Energy for the Office of Energy Efficiency and Renewable Energy had issued a letter providing a list of thirteen EE standards and actions—many of which refer to multiple EE measures—the Department of Energy intends to review in response to Executive Order 13990. (Tr. Vol. 3, p. 682-687; H. Ex. 21). While Mr. Grevatt relied upon orders from Maryland and Colorado to assert that the Commission should establish EE savings goals in these IRP dockets, he acknowledged that the Commission has approved 1% savings goals for the Companies—based on a settlement entered into by his clients—until 2026. (Tr. Vol. 3, p. 687-91.) He further admitted that his proposal to set savings goals was not based on any analysis or evaluation, as required by Act 62, but was instead aspirational. (Tr. Vol. 3, p. 691-95.)

<u>Commission Determination</u>

Act 62 requires IRPs to "include an evaluation of low, medium, and high cases for the adoption of . . . energy efficiency, and demand response measures." S.C. Code Ann. § 58-37-40(B)(1)(e)**.** The Commission finds that the Companies' evaluations of the low, medium, and high cases for the adoption of EE/DSM measures comply with Act 62 of Act 62 and are reasonable. The Market Potential Studies were accurate, robust, and comprehensive, and the Companies' inputs and methodology were evidence-based and specific to the utility's system, geographic territory, and customers, thereby ensuring that the modeling was accurate and appropriate for use in resource planning. We do not agree with the Environmental Parties that the Companies should increase EE savings based on unidentified "emerging technologies" and agree with the Companies' testimony that such an approach to resource planning would artificially reduce the load forecast, introducing reliability risk with no attendant benefit. The Environmental Parties' proposal to assume EE/DSM savings rates of up to 2% of retails sales is similarly rejected as not being evidence-based and failing to square with the purpose of reliable system planning.

Contrary to the approach advocated for by witnesses for the Environmental Parties, this is not an aspirational proceeding. In contrast, according to S.C. Code Ann. § 58-37-10(2), an IRP is "a **plan** which . . . contains the supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner." S.C. Code Ann. § 58-37-10(2) (emphasis added). As discussed in Mr. Bak's testimony, EE-based demand and energy savings are treated as a reduction to the load forecast, and DSM programs—also sometimes referred to as demand response programs—are treated by the IRPs as dispatchable resource options. It is therefore important that the EE/DSM estimates be sound and based upon data specific to the Companies' customers and service territory. We find that the Market Potential Studies commissioned by the Companies to this end are reasonable and were reasonably relied upon by the Companies. While the Market Potential Studies used the TRC test, which was effective at the time of the study and at the time of the filing of the IRPs, the Companies included a sensitivity to estimate the potential savings based on the UCT, and also did not rely exclusively upon the Market

Potential Studies for estimating savings in the short-term, instead blending the Companies' respective five-year program planning forecast into the long-term achievable potential projections from the Market Potential Studies. No testimony or evidence was proffered that challenged or questioned the Companies' use of the UCT sensitivity or the method used by the Companies to estimate short-term savings, and we find them to be reasonable.

We find and conclude that the Market Potential Studies' reliance upon data specific to the Companies' customers—rather than relying upon savings levels from other jurisdictions or upon generic data from the Energy Information Administration—was reasonable. Further, having taken judicial notice of Order Nos. 2021-32 and 2021-33, we note that the Companies have committed themselves to pursuing a 1% annual EE savings goal until 2026, and there is no evidence in the record supporting the recommendation that the Companies should assume or model savings goals of up to 2% as proposed by the Environmental Parties. We agree with Witness Bak that inflating EE savings estimates could compromise the accuracy and soundness of the IRPs and thus compromise the power system reliability contrary to prudent resource planning and the mandates of Act 62.

We agree with ORS's critique that the low EE/DSM scenario should be more precisely developed, particularly given evidence in the record that certain factors could lead to a low EE/DSM outcome, including new efficiency codes and standards implemented by the new federal administration, as well as shifting economic conditions or changes in the market. We therefore direct the Companies to include a more detailed low EE/DSM scenario in its next comprehensive IRP.

3. Other Considerations Beyond the Scope of IRP Proceedings under Act 62

a. *Fundamental Market Reforms*

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NOS. 23-24

Summary of the Evidence

The evidence in support of these findings of fact are found in the Companies' 2020 IRPs, pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

ORS highlighted the Companies' recently filed notice with the NCUC (and now with the Federal Energy Regulatory Commission ("FERC")) of the Companies' intent to establish and join the Southeast Energy Exchange Market ("SEEM").[13] SEEM is a region-wide, automated, intra-hour platform that matches buyers and sellers with the goal of more efficient bilateral energy trading and assumes utilization of unused transmission capacity to achieve cost savings for customers in the Southeast. ORS recommended that the Companies provide details regarding the status of the SEEM, details regarding important current and planned activities, and information regarding the monetary benefits that have been achieved by implementation of the SEEM. (H. Ex. 24, ORS DEC Report, pp. 11, 102, 114, 206.)

CCEBA Witness Lucas argued that the Companies' IRPs "overlook[] the benefits of regionalization." (Tr. Vol. 2, p. 501.106.) Witness Lucas also recommended that the Companies seek regulatory approval to allow them to combine the DEC and DEP balancing authorities, file joint IRPs, and share firm capacity between the two systems on an unrestricted basis. (Tr. Vol. 2, p. 501.106.) In addition, Witness Lucas suggested that the Companies should study the potential benefits of broader regionalization through wholesale market structures such as an energy

[13] *S. Co. Servs. Inc.,* Southeast Energy Exchange Market Agreement, Docket No. ER21-1111-000 (filed Feb. 12, 2021). The SEEM proposal remains pending before FERC as of the time of this Order.

imbalance market ("EIM") or regional transmission organization ("RTO"), which he suggests could potentially deliver more significant benefits than SEEM. (Tr. Vol. 2, pp. 501.106, 501.111-13.) Similarly, Vote Solar Witness Fitch similarly contended that the Companies have declined to pursue beneficial regional coordination strategies, such as joint capacity planning or regional coordination beyond SEEM. Based on his assertion of benefits related to regional energy coordination, Witness Fitch recommended that the Commission direct the Companies to prepare an analysis, conducted by a third-party consultant, comparing the benefits of several regional coordination configurations, including but not limited to an EEM, and EIM, and an RTO. (Tr. Vol. 3, pp. 736.59-736.60, 736.63.)

In response, Witness Snider explained that a fulsome consideration of the costs and benefits of combining the DEC and DEP balancing authorities would involve "comprehensive, time consuming and expensive regulatory and analytical studies" and that the IRP is not the appropriate forum in which to undertake such an analysis. (Tr. Vol. 6, p. 1586.156.) He explained that FERC approved the Joint Dispatch Agreement ("JDA") between DEC and DEP in 2012, as part of the merger between Duke Energy Corporation and Progress Energy Corporation. (Tr. Vol. 6, p. 1586.154.) Witness Snider noted that Section 4.1 of the regulatory conditions, as approved by the NCUC and by this Commission, explicitly require that the Companies not transfer any rights to generation or transmission facilities between DEC to DEP or to construct generation or transmission facilities for the benefit of the other. (Tr. Vol. 6, p. 1586.155.) While the JDA does not set up a joint balancing authority, it enables DEC and DEP to transfer incremental economic energy between DEC's and DEP's generating fleets from the system with lower marginal costs to displace higher cost system generation on the other system. (Tr. Vol. 6, pp. 1586.154-55.) As Witness Snider explained, any change to this arrangement would require complex cost-benefit studies and regulatory approval from FERC, this Commission, and the NCUC. (Tr. Vol. 6, p. 1586.156.)

With respect to the ORS's recommendation, the Companies agreed to provide the Commission with an update on their participation in SEEM in future IRPs filed with the Commission. Witness Snider testified that, as the SEEM application remains pending before FERC, the only update the Companies could provide on this issue in a modified IRP in these dockets is that the SEEM Agreement was filed with FERC for approval on February 12, 2021. He also explained that, the impact that SEEM participation may have on the Companies' IRPs may be limited, since the sub-hourly non-firm real-time energy exchange opportunities that will be enabled under SEEM offer the potential to help reduce real time energy costs, but do not represent firm capacity. Once SEEM is approved and the participating utilities gain experience with the resultant non-firm energy flows and resulting savings, the Companies will discuss in future IRPs and the potential impacts of SEEM participation to the IRPs. The Companies will work with ORS to ensure that the information provided in future IRPs is appropriate and responsive to this recommendation. (Tr. Vol. 6, pp. 1586.155-56.)

The Companies opposed the recommendations of CCEBA and Vote Solar that the Commission require the Companies to study alternative EIM or RTO wholesale market structures as part of future IRPs. Witness Snider explained that such recommendations ask the Commission to invade the space already occupied by the General Assembly. (Tr. Vol. 6, p. 1586.161.) Witness Santoianni also commented that resource planning—modeling and planning how the Companies will meet their load obligations for the next 15 years—needs to be rooted in the regulatory and wholesale market structures in place at the time the IRP is created. Any study of new wholesale market structures should be conducted pursuant to the legislatively-approved process in South

Carolina and within the framework intended by legislators in South Carolina. Witness Santoianni also highlighted the passage of Act 187 establishing a legislative "Market Reform Study Committee" intended to evaluate, amongst other things, legal and procedural requirements associated with adoption of any recommended electricity market reform measures, including identification of existing laws, regulations, and policies that may need to be amended in order to implement the electricity market reform measures. (Tr. Vol. 5, pp. 1536.22-23.) The Commission's involvement in any effort by South Carolina to enter a different wholesale market structure would only occur if the General Assembly make a decision to move in that direction. (Tr. Vol. 6, p. 1586.161.)

Both witnesses Snider and Santoianni also highlighted the significant amount of resources required to develop an IRP (and the associated cost to customers) and emphasized that requests for more analysis and more scenarios should be tempered by the benefit they would actually bring to this process and to customers. (Tr. Vol. 6, pp. 1586.45-46; Tr. Vol. 5, p. 1536.24)

Discussion and Conclusions

In consideration of the above evidence, the Commission concludes that it is reasonable and appropriate that the Companies should provide, in future comprehensive IRPs, details regarding the status of SEEM and information regarding the benefits of participation in SEEM (if approved). As suggested by ORS, the SEEM updates can assist in keeping the Commission and stakeholders informed on the Companies' involvement in SEEM as well as on the benefits of participation in SEEM. The Commission also concludes based on the evidence presented that the recommendations of CCEBA's and Vote Solar's witnesses with respect to studying FERC-jurisdictional fundamental market reforms to the operation of the Companies' systems are not appropriate and are rejected as beyond the scope of this IRP proceeding under Act 62.

Wholesale power market constructs, whether SEEM or RTOs or EIMs, overseen and regulated by FERC under the Federal Power Act are, in many respects, beyond the scope of IRP planning under Title 58 of South Carolina's Code of Laws. The Commission also recognizes that the SEEM application is pending before FERC, and that such FERC proceedings can span a number of months. The Commission appreciates the Companies' willingness to provide updates on the establishment of SEEM and also recognizes that the degree to which SEEM participation will impact the IRPs is unclear, for the reasons discussed by Witness Snider. Assuming SEEM is approved by FERC, the Commission finds that the potential impacts of SEEM participation to the IRPs will become more apparent, as the participating utilities gain experience with the resultant non-firm energy flows and resulting savings. The Companies should provide details regarding the status of SEEM, and information regarding the benefits of participation in SEEM in the next comprehensive IRP to be filed in September 2022. The Companies should also work with ORS, as appropriate, to ensure that the information provided in future IRPs is responsive to ORS's recommendation.

The recommendations of CCEBA and Vote Solar are not reasonable and are rejected. Act 62 provides that, in determining whether an IRP is the most reasonable and prudent means of meeting energy and capacity needs, the Commission shall consider whether the plan appropriately balances, among other factors, "other foreseeable conditions that the Commission determines to be for the public interest." S.C. Code Ann. § 58-37-50(C)(2)(g). ORS's recommendation that the Companies provide updates on SEEM is reasonable as SEEM has been proposed and is pending before FERC and, if approved, may have some impact on future IRPs. Accordingly, the Commission finds that the Companies' plans to participate in SEEM, if authorized by FERC, is a "foreseeable condition" that may have at least some impact on long-term resource planning in these IRP proceedings. The CCEBA and Vote Solar recommendations, however, ask the Commission to direct the Companies to engage in speculative evaluation of alternative FERC-regulated wholesale power market structures or joint resource planning that are not, based on the evidence in this proceeding, foreseeable. Notably, when asked through discovery what actions the Commission should take in this proceeding in response to Witness Lucas's testimony relating to energy market reforms in South Carolina in light of the fact that the General Assembly is reviewing these issues, CCEBA conceded that it did not have any recommendations to make at this time. (Tr. Vol. 6. p. 1586.157; H. Ex. 42.)

The Commission recognizes that studying such far ranging fundamental market reforms and alternative market structures is more appropriately the purview of the General Assembly, particularly as the General Assembly is currently studying these issues as mandated by Act 187. The Commission agrees with Witnesses Snider and Santoianni that, while the IRP touches on many aspects of the utility business, an IRP proceeding was never intended to be, nor statutorily authorized to be, the procedural mechanism for addressing all emergent regulatory or legislative energy issues. The Commission also agrees with Witness Snider that an IRP proceeding is not the correct forum in which to consider combination of the DEC and DEP balancing authorities, and, accordingly, the Commission declines to order the Companies to undertake such a study.

Finally, the Commission agrees with the Companies' witnesses that IRPs should be designed to fully and robustly meet the requirements of Act 62, but need not address every conceivable area of study or potential inquiry that would potentially be of interest to stakeholders, ORS or even to the Commission. No single resource plan can address every possible study area of potential interest to parties nor can it envision all possible outcomes in an evolving industry. Rather, the planning process is repeated over time allowing for adaptations to inputs, changing study focus areas, as well as the incorporation of changing state and federal energy policies. Moreover, the Commission recognizes, based on the extensive record in this proceeding, that all of the studies, analyses, system modeling, and hiring of experts used in the development of the Companies' 2020 IRPs required significant resources. Significant ORS and Commission resources were also required to evaluate the IRPs' compliance with Act 62. All of these resources are ultimately paid for by customers. As such, it is important to ensure that any additional work requested in future proceedings is meaningful to the Companies' long-term planning process and impactful to the results.

b. *IRP Modeling and Transparency for Future IRPs*

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 25

The evidence in support of this finding of fact is found in the Companies' 2020 IRPs, pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

The Companies used the PROSYM production cost model for their 2020 IRPs. (H. Ex. 1, 2020 DEC IRP, p. 90; 2020 DEP IRP, p. 93) ORS finds the use of PROSYM to be reasonable (H. Ex. 24, ORS DEC Report, pp. 25, 30, 44, 128, 133, 147; Tr. Vol. 4. p. 958.), and no other party objects to the use of PROSYM. ORS did encounter some difficulty reconciling PROSYM data with information from other sources, including the Companies' Load, Capacity, and Reserves Table (the "LCR Table"), and recommends the Companies create a cross reference table comparing each resource modeled in PROSYM to the corresponding data in the LCR Table for the base case with carbon policy and the base case without carbon policy. (Tr. Vol. 3, pp. 816.5, 816.7; H. Ex. 24, ORS DEC Report, pp. 5, 10, 63, 65, 77, 108, 113, 168, 172, 184.)

Witness Snider disagrees that a cross reference table in the IRP is a feasible way to enhance transparency and avoid confusion, and proposes that the best format for supplying this comparison information is in a comparison worksheet, such as the information presented in Snider Rebuttal

Exhibit 6. The comparison worksheet provides information to direct the specific data item from PROSYM to the data source in the LCR Table, and explains differences in information tied to each of the two sources due to input differences. The Companies will prepare this comparison worksheet for the Base Cases in future IRPs as a standard discovery response included with the "Model Inputs" Excel files provided to ORS and other intervenors in discovery each year. (Tr. Vol. 6, p. 1586.85.) ORS accepted this approach. (Tr. Vol. 7, p. 2307.6.) Witness Snider also clarified that the Companies will transition to the Encompass modeling software platform for its 2021 and 2022 IRP updates and plans. (Tr. Vol. 6, p. 1586.86.)

Vote Solar Witness Fitch recommends that, in the interest of transparency, the Commission direct the Companies to procure licenses for modeling software "[t]o enhance collaboration between the Companies, Commission, and stakeholders and reduce regulatory and reputational risks." (Tr. Vol. 3, p. 736.57.) Witness Fitch supports his recommendation based on the fact that the Commission made a similar directive to DESC in DESC's IRP order. (*Id.*)

The Companies strongly oppose a requirement that they and, ultimately, their customers pay for licenses for intervenors that oppose the Companies' IRPs. Witness Snider testifies that imposing such an affirmative requirement for the Companies to fund the development of positions adverse to their interests goes well beyond the bounds of traditional discovery under both the Commission Rules and the South Carolina Rules of Civil Procedure. (Tr. Vol. 6, pp. 1586.162-63.) Act 62 provides for "*reasonable* discovery . . . to assist parties in obtaining evidence concerning the integrated resource plan, including the reasonableness and prudence of the plan and alternatives to the plain raised by intervening parties[.]" While Act 62 does not set finite parameters on the types of discovery that could be deemed "reasonable," ordering this type of access to the Companies' modeling software would impose an unprecedented and unreasonable burden on the Companies and their customers. (*Id.)* Witness Snider distinguishes ORS, which is granted special authority to make inspections, audits, and examinations of public utilities under South Carolina law, from other intervenors, which are limited to the traditional rights of parties. (*Id.)*

Witness Snider also distinguishes the context of DESC's IRP proceeding, in which the Commission found a similar recommendation to be appropriate, from the instant case. The Commission's ruling in the DESC IRP proceeding, which ordered DESC to acquire and pay for licenses to allow interested intervenors access the capacity expansion modeling software DESC will use for future IRP modeling, responded to significant accessibility and transparency concerns raised in intervenor testimony with regard to PLEXOS, the modeling platform DESC selected for future IRPs. Intervenors objected to the use of PLEXOS on multiple grounds, including the extreme cost to gain access, poor user interface, modeling limitations, as well as purported "transparency barriers" inherent to PLEXOS that render it difficult to export inputs and outputs in useable format. (Tr. Vol. 6, p. 1586.164.) The Commission found that DESC's use of PLEXOS did not comply with industry best practice and in addition required DESC to obtain input from stakeholders and the Commission on the selection and implementation of capacity expansion modeling software, in effect directing DESC to reconsider its selection of PLEXOS. Unlike DESC, the Companies have selected Encompass, a lower cost capacity expansion and production cost modeling software that has not been the subject of similar criticism, for its future IRPs, and no evidence has been presented that the same issues will arise with Encompass as did with PLEXOS. (*Id.)*

Finally, Witness Snider notes that while Vote Solar couched its request in terms of "promoting transparency," the Companies already voluntarily make reasonable efforts to promote transparency around their IRPs, including but not limited to extensive engagement with stakeholders throughout the IRPs' development, which involves the Companies' sharing inputs used in the modeling process. Considering the complexity and time-consuming nature of capacity expansion and production cost modeling, he states that this is the more appropriate path to achieve Witness Fitch's goal of engaging with the models rather than simply procuring a license. (Tr. Vol. 6, pp. 1586.165-66.)

Discussion and Conclusions

In consideration of the above evidence, the Commission concludes that the Companies' capacity expansion and production cost modeling approach in the 2020 IRPs was reasonable and that the Companies and ORS have reasonably resolved ORS's recommendation for enhanced transparency regarding PROSYM inputs and the corresponding data in the LCR table. The Commission also concludes that Vote Solar's recommendation that the Companies pay for software licenses for intervenors in these proceedings is inappropriate and should be rejected.

Act 62 requires utilities to provide "data regarding the utility's current generation portfolio, including the age, licensing status, and remaining estimated life of operation for each facility in the portfolio," S.C. Code Ann. § 58-37-40(B)(1)(f), and directs the Commission to assess the Companies' "diversity of generation supply." S.C. Code Ann. § 58-37-40(C)(2)(f). No evidence was presented that the Companies' use of PROSYM did not meet this requirement or allow the Commission to fulfill its duties under Act 62. The Commission therefore concludes that the Companies' modeling approach for the 2020 IRPs was reasonable. Going forward under Encompass, the Companies and the ORS have agreed to a process that should relieve the confusion between the model inputs and LCR table.

The Commission does not accept Vote Solar's recommendation that the Companies pay for production cost modeling software licenses for intervenor use. No other party other than Vote Solar supported this recommendation. The Commission finds that this recommendation clearly exceeds the bounds of discovery as prescribed by Act 62, which provides that in addition to allowing intervention by interested parties in proceedings established to review electric utility's IRPs, the Commission "shall establish a procedural schedule to permit reasonable discovery … in order to assist parties in obtaining evidence concerning the [IRP], including the reasonableness and prudence of the plan and alternatives to the plan raised by intervening parties." S.C. Code Ann. § 58-37-40(C)(1). Requiring the utility and its customers to pay for a software license for use by intervening parties is not "reasonable" discovery, particularly for a party like Vote Solar that does not have statutory investigatory authority such as that granted to ORS. Given the Companies' willingness to share input/output data through the discovery process, it would be even more inappropriate to ask ratepayers to cover the cost of these software licenses for any intervenor that may request it.

In addition, the circumstances under which the Commission imposed this requirement on DESC were distinct from the present proceeding. In the DESC case, the evidence showed that in developing its 2020 IRP, DESC did not use capacity expansion software, which is widely used in the electric utility industry, but instead chose a set of resource plans and then analyzed the cost of those plans. The Commission concluded in that case that this "needle-in-a-haystack" approach fell short of industry best practices, and that it was reasonable to require DESC to both negotiate a discounted licensing fee that permits interested intervenors the ability to perform their own modeling runs in the same software package as DESC, and to direct DESC to absorb the cost of those licensing fees. Order No. 2020-832 at 92, Docket No. 2019-226-E (Dec. 23, 2020). The

Commission also expressed concerns about the cost of the PLEXOS modeling tool utilized by DESC. None of these factors is present here. For the 2021 IRP update and 2022 comprehensive IRPs, the Companies are planning to transition to the use of Encompass to model capacity expansion and production costs, and no party has presented evidence that similar issues exist with respect to Encompass. As a result, the fact that the Commission required DESC to provide licenses to intervenors does not justify or support the imposition of the same requirement in this case and the Commission declines to do so for the reasons stated herein.

c. *All-Source Procurement*

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 26

Summary of the Evidence

The evidence in support of this finding of fact is found in the testimony of Environmental Parties Witness J. Wilson, the testimony during the hearing, and the entire record in this proceeding.

In surrebuttal testimony, Environmental Parties Witness J. Wilson filed testimony for the first time. In support of his surrebuttal testimony, he filed a 55-page report he co-authored entitled *Implementing All-Source Procurement in the Carolinas* and a 62-page report that he authored entitled *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement* (together, the "All-Source Procurement Reports"). The All-Source Procurement Reports were attached as Exhibit JDW-2 and JDW-3, respectively, to Witness Wilson's surrebuttal testimony and presented for the first time in this proceeding an alternate approach to the Companies' established procurement process. Witness Wilson recommended that the Commission direct the Companies to implement an all-source procurement approach to integrated resource planning and generation procurement and certification. (Tr. Vol. 7, p. 2098.18.) According to Witness Wilson, the solicitation of bids to meet DEC's and DEP's total system need for the entire 2026 to 2031 time period would enable the Companies to obtain price and performance information about generation alternatives directly from the marketplace and to identify "unanticipated" opportunities to efficiently meet electricity needs. (Tr. Vol. 7, p. 2096.) On cross-examination, Witness Wilson admitted that none of the South Carolina laws and regulations cited in his testimony—Section 58-41-20(E)(2) (regarding the competitive renewable energy procurement process) and Section 58-33-10 (the "Utility Facility Siting and Environmental Protection Act") — were part of the IRP section of Act 62. (Tr. Vol. 7, pp. 2109-12.)

The All-Source Procurement Reports and testimony of J. Wilson presenting these Reports for the first time in surrebuttal was included in the Companies' April 19, 2021, Motion to Strike, which was renewed by the Companies on June 9, 2020. At the hearing, Witness Wilson confirmed that he did not file direct testimony in this case (Tr. Vol. 7, p. 2099), and that his All-Source Procurement Reports were dated February 26, 2021, filed in North Carolina on March 1, 2021, and not filed in the instant case until April 15, 2021. (Tr. Vol. 7, pp. 2101-2102.)

Commission Conclusions

The Commission grants the Companies' renewed motion to strike with regard to Witness Wilson's surrebuttal testimony and supporting exhibits. Upon further review, Mr. Wilson's testimony and exhibits are new matters that are unrelated to issues raised to date in these proceedings. As such, the Companies had no reasonable opportunity to investigate Witness Wilson's recommendations through discovery or provide testimony responding to these recommendations. Allowing them into the record would effectively prohibit the Commission from fully vetting these alternative planning recommendations as required by Act 62.

As discussed above regarding the Synapse Report, we agree with the Companies that Witness Wilson's surrebuttal testimony and exhibits exceed the lawful scope of surrebuttal, as they do not respond to new matters raised in the Companies' rebuttal, but rather introduce a completely new argument that the Commission should fundamentally reshape the generation procurement process in South Carolina. Surrebuttal testimony must be limited to replying to new matters raised in rebuttal testimony, as it would be fundamentally unfair for a party to raise an issue for the first time in surrebuttal testimony without the party with the burden of proof, in this case the Companies, being given a corresponding opportunity to introduce responsive evidence.

While Witness Wilson's surrebuttal testimony purports to respond to the rebuttal testimony of DEC/DEP Witnesses Snider, Kalemba, and Wintermantel and suggests—without any meaningful explanation—that his new all-source procurement model recommendation could resolve numerous disputed issues between the Companies and intervenors, at its core, the testimony is a completely new argument (and unprecedented attempt) to fundamentally reshape the generation procurement process in South Carolina and is only tangentially related to the Companies' as-filed IRPs and corresponding direct and/or rebuttal testimony. Specifically, Witness Wilson recommends that the Commission require the Companies to fundamentally reshape their resource planning and generation procurement functions and to adopt a new all-source procurement model to procure new capacity resources to meet the Companies' identified future capacity needs. Witness Wilson's surrebuttal and accompanying exhibits are only related to the Companies' as-filed IRPs. (Tr. vol. 7, p 2098.2.) Witness Wilson's complaint that in their rebuttal testimony, the Companies rejected Environmental Parties' critiques of the Companies' assumptions and modeling of generation alternatives does not justify introducing an entirely new approach to integrated resource planning in this State; the proper approach would have been for Witness Wilson to raise this all-source procurement recommendation in direct testimony and to then engage with the Companies' rebuttal arguments directly.

Environmental Parties' filing this significant new testimony and these voluminous new exhibits in surrebuttal advocating for an All-Source Procurement Process also violates Act 62's provision for "reasonable discovery" in IRP proceedings. Where, as here, there were only 12 calendar days between the filing of surrebuttal testimony and commencement of the hearing, there is insufficient time for the Companies to conduct any meaningful discovery—much less "reasonable" discovery—on the hundreds of pages of any new testimony issues presented by the Clean Energy Intervenors, thus depriving the parties and the Commission the opportunity to fully vet the alternative recommendations proposed by intervenors in surrebuttal testimony as required under Act 62.

Environmental Parties have not made any arguments—much less credible arguments—that Witness Wilson's prefiled testimony and the All-Source Procurement Reports could not have been submitted as part of their direct case. Commission Order No. 2020-715 established the procedural schedule and set the hearing date for these proceedings on October 21, 2020—over 105 days prior to the date these Advocacy Groups filed their direct cases. Environmental Parties' filing of these alternative plans and recommendations only days before the hearing placed the Companies and other parties at a significant disadvantage in preparing for and participating in the evidentiary hearing. Tellingly, Witness Wilson does not identify any specific information or data provided in the Companies' rebuttal testimony which prohibited the Environmental Parties from proposing that the Companies adopt an all-source procurement model in their direct case. He could not do so as the All-Source Procurement Reports are dated February 26, 2021 meaning that—like the Synapse Alternative Plan—they were completed *before* the Companies filed their rebuttal testimony.

Environmental Parties' tactic also impedes the Commission in discharging its duty under Act 62 to vet these alternative planning recommendations and in making its determination as to whether the Companies' proposed IRPs "represent the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs[.]" S.C. Code Ann. § 58-37-40(C)(1)-(2). Rather than ensuring Witness Wilson's Reports were prepared in time to file with their direct case in this proceeding or seeking leave to file supplemental direct testimony and to amend the procedural schedule, the Environmental Parties instead held on to the All-Source Procurement Reports and related recommendations for nearly two months before making these significant arguments in Wilson's surrebuttal testimony 12 days before the evidentiary hearing commenced. Witness Wilson, when asked at the hearing why the reports were not filed earlier, was not able to provide any reasons for the delay other than that the reports were completed after the deadline for direct testimony, but could not explain why they were not filed until April 15. The Commission does not find Witness Wilson's answers to these questions to be satisfactory. Including Witness Wilson's proposal and accompanying All-Source Procurement Reports in surrebuttal testimony prevented the Companies from conducting meaningful discovery or filing responsive testimony prior to the hearing in this proceeding, and prevented the Commission from meeting its duty under Act 62 to properly evaluate alternative planning recommendations.

Accordingly, consistent with settled South Carolina law that parties may not raise new issues on surrebuttal as well as Act 62's directive to allow for reasonable discovery and to ensure full vetting of alternative recommendations to inform the Commission's review of the Companies' IRPs, the Commission grants the Companies' renewed motion to strike Mr. Wilson's testimony in its entirety, including exhibits JDW-1, JDW-2 and JDW-3, from the record in this proceeding.

The Commission also notes that Act 62 prescribes the Commission's continuing review of the Companies' IRPs and the Companies are planning to file their next comprehensive IRPs in September 2022. If they wish, Environmental Parties will have the opportunity to intervene and timely refile these materials in that next IRP proceeding under the procedural schedule established by the Commission at that time to inform the Companies future resource plans.

C. Approval of 2020 IRPs as Most Reasonable and Prudent Plans

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 27-31

Summary of the Evidence

The evidence in support of this finding of fact is found in the Companies' 2020 IRPs, pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

Witness Snider testified that the 2020 IRPs are total plans that represent the most reasonable and prudent means of meeting customers' energy and capacity needs under a variety of conditions that could be experienced in the future. (Tr. Vol. 1 pp. 60, 62.36; Vol. 6. p. 1608.) He asserted that the six long-term resource portfolios that make up the 2020 IRPs appropriately balance resource adequacy and power supply reliability, customer affordability, regulatory compliance, commodity price risk, and plan for diversity of both supply-side and demand-side resources. According to Witness Snider, the optionality of the portfolios will enable the Companies to meet their unique obligation to continually, affordably, and reliably serve customers' energy and capacity needs. (*Id.*)

CCEBA Witness Lucas argued that the Companies' IRPs should be rejected because DEC and DEP present multiple long-term planning pathways, but do not explicitly select a single "preferred resource plan" portfolio. (Tr. Vol 3. pp. 501.12-18.) In response, Witness Snider explained that Act 62 affirmatively *requires* utilities to develop multiple portfolios to "fairly evaluate the range of demand side, supply side, storage, and other technologies and services available to meet the utility's service obligations." (Tr. Vol 6. pp. 1586.40-42.) Witness Snider stated that the legislative purposes behind requiring multiple portfolios is to inform stakeholders, including the Commission, on "how variables changes from one portfolio to the other, how costs change, what it takes, what policies, what are the benefits and risks, how do different technologies look in different portfolios." (Tr. Vol 6. p. 1614.) Witness Snider explains that "the IRP is the Integrated Resource Plan. The Integrated Resource Plan has six portfolios. I don't see anywhere in Act 62 where the Commission is bound to pick a resource portfolio within the Integrated Resource Plan. It doesn't say 'pick a portfolio.' Act 62 says 'develop an Integrated Resource Plan.'" (Tr. Vol 6. pp. 1707, 1823.)

ORS Witnesses Hayet, Baron, and Kollen developed extensive Reports analyzing the Companies' respective 2020 IRPs in the context of the criteria set forth in S.C. Code Ann. § 58-37-40(C)(2). (H. Ex. 24; H. Ex. 25.)

Upon initial review of the Companies' 2020 IRPs and direct testimony, ORS concluded that the Companies "did comply with all of the requirements of Section 40(B)" but that there were improvements that could be made to the Companies' IRPs. (Tr. Vol. 3, p. 851; H. Ex. 24, p. 23; H. Ex. 25, p. 23.) Specifically, ORS, informed by the Kennedy Associates witnesses, made 26 recommendations related to the Companies' 2020 IRPs—18 of which ORS recommended the Companies provide in a modified IRP in the instant proceeding and 8 of which ORS recommended the Companies address in a future IRP filing. (Tr. Vol. 3, pp. 816.3-7; 851.) ORS Witness Hayet explained that some ORS recommendations sought additional information related to the Section 40(B)(1) categories, while others sought "general explanations of how values were derived[,]" and still others sought further justification for or alternatives to DEC/DEP's modeling assumptions and inputs. (Tr. Vol. 3, pp. 851-52.)

In response, Witness Snider acknowledged that ORS has the unique role of representing the public interest by providing a balanced assessment of the reasonableness of these varying assumptions as it pertains to the requirements in Act 62. (Tr. Vol. 6, p. 1586.21.) He stated that

ORS and their technical consultants, Kennedy Associates, have undertaken a reasonable, technically objective and holistic review of the 2020 IRPs' compliance with Act 62. (Tr. Vol. 6, p. 1586.13.) As a result, the Companies agreed with the vast majority of ORS's recommendations and provided extensive and detailed information and explanation to proactively address each of ORS's 26 recommendation in their rebuttal testimony. With the exception of two disputed issues, the Companies either provided the additional information in testimony or exhibits or agreed to address the recommendation in a future IRP filing as suggested by ORS. (Tr. Vol. 6, pp. 1586.26-27.) In surrebuttal testimony, ORS' witnesses agreed that the Companies' response resolved all but two recommendations for improvements to the satisfaction of ORS. (Tr. Vol. 3, p. 824.) Witness Hayet's Tables 1 and 2 summarized each of the recommendations and their corresponding resolution status as follows:

Table 1
Recommendations for DEC and DEP in this IRP

Item	Recommendations for DEC and DEP in this IRP	Status	Addressed by ORS Witness
4	Recommended Companies provide detailed discussion in IRP Reports or appendices explaining how Astrapé 2018 Solar Capacity Value Study results were used to derive the assumed winter peak standalone solar capacity value of 1%. Recommended this information be included in a modified IRP in this proceeding.	Additional information provided in Kalemba Section V. Resolved.	Hayet
5	Recommended Companies provide additional justification for selecting the Base Energy Efficiency ("EE")/Demand Side Management ("DSM") case as opposed to the High EE/DSM case for use in Portfolio A, given that the High EE/DSM case may provide greater customer benefits. Recommended this information should be included in a modified IRP in this proceeding.	Additional justification provided in Snider Exhibit 11. Resolved.	Hayet

Item	Recommendations for DEC and DEP in this IRP	Status	Addressed by ORS Witness
6	Recommended that in addition to the sensitivity cases included in Table A-9, the Companies also evaluate high and low levels of EE/DSM using high fuel/CO2 and low fuel/CO2 assumptions. Recommended this information be included in a modified IRP in this proceeding.	Resolved for this IRP. However, this should be discussed further in the IRP Stakeholder process.	Hayet
9	Recommended the Companies provide tables summarizing the capital and operations and maintenance ("O&M") costs for compliance with environmental regulations by unit and by environmental regulation, and include descriptions explaining those costs. Recommended this information be included in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 10. Resolved.	Hayet
10	Recommended the Companies create a cross reference table that compares each resource modeled in PROSYM, including generating units, demand response, purchase contracts, sales contracts, EE, etc. to the corresponding data in the Load, Capacity and Reserves ("LCR") table, on a resource by resource basis. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 6. Resolved.	Hayet
11	Recommended the Companies supply additional information regarding its Nuclear Unit relicensing plans (including a timeline) and its plans to conduct economic evaluations to assess the benefits of relicensing the units. Also, recommended the Companies provide additional insight into why it is beginning this process so far in advance of the relicensing dates. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 7. Resolved.	Hayet
12	DEC Only - Recommended that DEC provide the status of its plans to relicense the Bad Creek Pumped Hydro units, including any actions it will have to take as part of the relicensing process and any costs that it will incur to relicense the units. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 8. Resolved.	Hayet

Item	Recommendations for DEC and DEP in this IRP	Status	Addressed by ORS Witness
13	Recommended DEP and DEC provide additional clarification regarding their plans for the retirement of the Darlington and Allen units, respectively, including details about any transmission impacts, an explanation of the steps being pursued to receive final approval from any regulatory body, and a timeline for conducting these activities. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 15 (Darlington Units), and Snider Exhibit 17 (Allen Units). Resolved.	Hayet
14	Recommended the Companies provide evidence that the optimal retirement dates determined with the Sequential Peaker Method ("SPM") are comparable to the optimal retirement dates the System Optimizer model would produce if it were used in the retirement study. Recommended this information be provided in a modified IRP in this proceeding.	See Snider Rebuttal Testimony, beginning at page 84. The Companies are willing to collaborate with stakeholders and evaluate Encompass' capabilities to potentially improve the modeling process. Resolved.	Hayet
15	Recommended the Companies supply additional information explaining the basis for how Combined Heat and Power ("CHP") resources were added to the short-term action plan, and explain why CHP resources were not treated as selectable resources in the economic optimization process, if in fact they were not. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 16. The treatment of CHP resources in future IRPs should be considered in the stakeholder process. Resolved.	Hayet
16	Recommended the Companies provide additional justification for its Combustion Turbine ("CT") capital cost assumption. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 9. Resolved, but discuss the reasonableness of basing the CT cost on building 4 CT units at a site in a future stakeholder process	Hayet
17	Recommended the Companies provide additional justification for its Battery Energy Storage fixed O&M cost and capacity factor assumptions. Recommended this information be provided in a modified IRP in this proceeding.	Addressed in both Mr. Snider's and Mr. Kalemba's testimony. Resolved, but battery storage capacity factor should be re-examined when the Companies begin using Encompass.	Hayet

Item	Recommendations for DEC and DEP in this IRP	Status	Addressed by ORS Witness
18	Recommended the Companies include an additional solar generic resource option in its IRP modeling assumptions that reflects the kind of solar Purchase Power Agreements ("PPA") prices that may be available in the market. As a proxy, the Companies could assume $38/megawatt-hour ("MWh") as the solar PPA cost. Recommended this be addressed in a modified IRP in this proceeding.	Unresolved. The Companies should be required to adopt market-based solar PPAs in the 2021 update IRP.	Hayet
20	Recommended the Companies provide a table identifying each renewable resource option that was modeled, and include whether the resource was forced-in or economically selected (System Optimizer or other approach), the reason the resource was forced-in (e.g. Competitive Procurement of Renewable Energy Program ("CPRE"), Act 236, etc.), whether the resource is a designated, mandated, or undesignated resource, and where the resource is found in the PROSYM database and in the LCR tables for reconciliation purposes. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Kalemba Exhibit 1. In future IRPs, should the Companies follow the same categorization process, additional information should be included regarding whether resources were forced-in or economically selected. Resolved.	Hayet
21	Recommended the Companies include post in-service capital costs for new resource additions in its capital cost model and its Present Value of Revenue Requirement ("PVRR") calculations for each Portfolio and each sensitivity of each Portfolio. Recommended this be addressed in a modified IRP in this proceeding.	See Snider Rebuttal Exhibit 12. The Companies should separate out these costs in future IRP filings and identify them as post in-service capital additions. Resolved.	Kollen
22	The average retail rate impacts are an important consideration when assessing whether Portfolios and the pathways reflected in those Portfolios are reasonable. This should be considered in this IRP and future IRPs, but it does not require a modified IRP in this proceeding.	This recommendation only pointed out that this is important information to be considered in evaluating a utility's IRP. Resolved.	

Item	Recommendations for DEC and DEP in this IRP	Status	Addressed by ORS Witness
23	Recommended the Companies revise the calculation of the average retail rate impact on customers so that the assumptions and methodologies are consistent with the calculations of the PVRR, except for the levelization of the capital-related costs. Recommended this be included in a modified IRP in this proceeding.	Unresolved. Companies are amenable to addressing this in the Stakeholder process. ORS recommends this be done before the next IRP Update in 2021.	Kollen
24	Recommended the Companies provide additional details and status updates about resources included in the action plan, including coal retirements, the Lincoln CT project, unnamed energy storage projects, nuclear uprates, Bad Creek upgrades, and unnamed CHP projects. Recommended this information be included in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 14. Company also committed to provide this information in future IRPs. Resolved.	Hayet

Table 2

Recommendations for DEC and DEP in a Future IRP

Item	Recommendations for DEC and DEP in a Future IRP	Status	Addressed by ORS Witness
1	Recommended the Companies provide more detailed discussions describing each of the load forecasting models, statistical results, and the individual energy and peak load forecast results. Recommended this level of detail be included in a technical appendix to the IRP.	Companies offer to provide this information in response to discovery, not as a technical appendix. (Snider Rebuttal Testimony, beginning at pg. 50, ln. 15). Resolved.	Baron
2	Recommended the Companies provide a more detailed discussion of the specific reliability methodology used to develop the synthetic loads for extreme low temperature periods in a technical appendix to the IRP.	Companies agreed to provide this information in future IRP proceedings. (Snider Rebuttal Testimony, pg. 53, ln. 12 - 17). Resolved.	Baron

Item	Recommendations for DEC and DEP in a Future IRP	Status	Addressed by ORS Witness
3	Recommended further development of the reliability methodology to model the effects of extreme low temperatures on winter peak load. Recommended this be addressed in future IRPs through the Companies' stakeholder process.	Witness Snider stated that this issue is critical to resource adequacy planning and further development would take place. (Snider Rebuttal Testimony, beginning at pg. 54, ln. 1). Resolved.	Baron
7	The Companies provided no basis for the low EE/DSM forecast. Recommended additional justification be provided or consider other approaches for deriving the low EE/DSM forecast. Recommended this be addressed in future IRPs through the stakeholder process.	Witness Bak agreed to address this "with stakeholders for their next IRPs." (Bak Rebuttal Testimony, beginning at pg. 19, ln. 3). Resolved.	
8	Recommended the Companies review their natural gas price forecasting methodology and investigate alternative approaches. Recommended this be addressed in future IRPs through the stakeholder process.	Witness Snider stated this would be addressed in a future IRP Stakeholder process. (Snider Rebuttal Testimony, beginning at pg. 64, l. 19). Resolved.	
19	Given the importance that solar capacity values and solar plus battery energy storage capacity values potentially could have on the IRP analysis, ORS recommended that further investigation be conducted regarding these values with stakeholder input, discussed as part of a stakeholder engagement process.	Witness Kalemba states the Companies are open to discussing this issue with Stakeholders, and would consider performing additional sensitivities in future IRPs. (Kalemba Rebuttal Testimony, beginning at pg. 43, l. 8). Resolved.	
25	Recommended in future IRPs, additional details be provided regarding the status of the Southeast Energy Exchange Market ("SEEM").	Witness Snider stated this would be provided in future IRPs. (Snider Rebuttal Testimony, pg. 151, ln. 20 – 22.). Resolved.	

Item	Recommendations for DEC and DEP in a Future IRP	Status	Addressed by ORS Witness
26[14]	Recommended that the Companies perform risk analyses in future IRPs.	The Companies agreed. (Snider Direct Testimony at pg. 143, ln. 16). Resolved.	Kollen

(Tr. Vol. 7, pp. 2307.5-2307.11.)

Regarding the two outstanding disputed issues, the Companies' Witnesses addressed both issues in testimony. First, the Companies agreed to include a solar PPA resource option as a sensitivity to the two base cases in the 2021 IRP Update. Second, the Companies agreed to collaborate with ORS before the next comprehensive IRP on refining the calculation of the average retail rate impact on customers for consistency with other IRP analyses where appropriate. (Tr. Vol. 6, pp. 1586.147-148.)

With the additional information provided and the Companies' commitment to address other issues in the next IRP, ORS found the 2020 IRPs to be reasonable and meeting the requirements of Act 62. In particular, Witness Hayet noted that in the context of an IRP, "[r]easonable[ness] is measured by things such as: Is it best industry practices? Are the assumptions reasonable? Did they conduct analyses? Did they collaborate with parties to discuss assumptions? And on those scores, the answer is yes. So we reach[ed] a conclusion it is a reasonable plan." (Tr. Vol. 3, pp. 895-96.) Witness Hayet further opined that, based on his more than 30 years of experience and benchmarking to the more than 100 IRPs he has reviewed, the 2020 IRPs are reasonable and

[14] This recommendation was addressed by ORS witness Kollen at p. 11 of his Direct Testimony, but it was not previously assigned a recommendation number. It is now Recommendation 26.

prudent. (Tr. Vol. 3, pp. 886, 896.) Similarly, ORS Witness Kollen opined that the 2020 IRPs "address a broad and reasonable range of demand-side, supply-side storage and other technologies as required by Act 62" based on "a reasonable set of sensitivity analyses." (Tr. Vol. 4, p. 958.) He noted that the Companies' IRPs were "unequivocally" better than the IRPs initially submitted by Dominion Energy South Carolina and Lockhart Power Company. (Tr. Vol. 4, p. 979.) According to Witness Kollen, the "level of sophistication is substantially different." (*Id.*)

On behalf of ORS, Witnesses Sandonato and Hayet testified that the 2020 IRPs are reasonable and meet all of the requirements in Act 62, but stated that the ORS's review did not attempt to determine whether the 2020 IRPs were the "most reasonable and prudent" plan. (Tr. Vol. 3. pp. 828, 894.) Importantly, Witness Hayet acknowledged that the 2020 IRPs "balance[d] the seven factors" the Commission must consider under Section 58-37-40(C)(2), adopted "best industry practices," incorporated "reasonable assumptions," "collaborate[d] with parties to discuss assumptions," and "conduct[ed] analyses" to find the best models. (Tr. Vol. 3. p. at 894.) Looking at the Companies' load forecast, resource adequacy assessment, 17% reserve margin, fuel cost modeling, and other factors, ORS determined that the Companies' plan was reasonable and not an outlier when compared to forecasts of other utilities as well as other information sources. (Tr. Vol. 3. p. at 902.) In closing, Witness Hayet pointed out that while the Commission is tasked with approving the "most reasonable and prudent plan," "the IRP doesn't give the company [sic] the authority to recover their costs" for any construction or project contemplated in the IRP. (Tr. Vol. 3. p. 903-04.)

ORS also suggests that the Companies selected the Base Case Without Carbon Policy Portfolio as their preferred plan for purposes of avoided cost proceedings, value of solar calculations, cost-effectiveness, and DSM evaluations. (H. Ex. 24 DEC ORS Report, p. 20-2; DEP

ORS Report, p. 20-2). Witness Snider explained that under current regulatory and statutory policies that are in place today, the Companies believe the Base Case Without Carbon Policy is the "appropriate plan" for consideration and use by the Companies in the ongoing avoided cost proceedings and other imminent regulatory matters because it (1) represents the least cost plan under current policy assumptions; (2) includes a considerable amount of new renewable resources; (3) relies on resources that are commercially available today; and (4) is a flexible plan that can easily be modified to allow more renewable resources to be added. (Tr. Vol. 6. pp. 1586.42-43, 1611-1616-13.)

Witness Snider also explained that the Companies' prepared a Short-Term Action Plans for DEC and DEP that identify accomplishments in the past year and actions to be taken over the next five years under both base cases. In particular, the Short-Term Action Plans, which are described in Chapter 14 of the DEC and DEP IRPs, explain steps the Companies plan to take to, among other things, (1) grow the amount of EE and DSM resourced to meet customer growth; (2) grow their renewable generation and resource portfolio; (3) invest in grid-connected storage systems; (4) implement a grid improvement plan; (5) pursue potential opportunities for wholesale power sale agreements within the Companies' balancing authorities; take steps to meet the Companies' long-term goal of net-zero carbon emissions by 2050; (6) renew nuclear licenses; and (7) adopt clean natural gas resources and look to enhance existing clean resources. (H. Ex. 1, DEC IRP, pp. 116-130.) However, the additional five portfolios allow the Companies to readily shift course in the event of any policy change.

<u>Commission Conclusions</u>

Section 58-37-40(C) instructs the Commission to determine whether an IRP is "the most reasonable and prudent means of meeting energy and capacity needs[.]" In making that determination, Section 58-37-40(C)(2) provides that the Commission should consider whether the IRP appropriately balances a variety of factors, including:

(a) resource adequacy and capacity to serve anticipated peak electrical load, and applicable planning reserve margins;
(b) consumer affordability and least cost;
(c) compliance with applicable state and federal environmental regulations;
(d) power supply reliability;
(e) commodity price risks;
(f) diversity of generation supply; and
(g) other foreseeable conditions that the commission determines to be for the public interest.

As a threshold matter, CCEBA contends that the Commission should not approve the 2020 IRPs because they present six portfolios, and the Companies do not pick a single plan, for Commission approval. We disagree with that interpretation of Act 62. As Witness Snider pointed out, Act 62 is clear that the Companies *must* include "several resource portfolios" in their IRP plan. S.C. Code Ann. § 58-37-40(B)(1)(e) (emphasis added) ("An integrated resource plan *shall include* all of the following: . . . several resource portfolios developed with the purpose of fairly evaluating the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's service obligations.") The Commission is then tasked with "hav[ing] a proceeding to review each electrical utility's integrated resource plan" and "shall approve an electrical utility's integrated resource plan if the commission determines that *the proposed integrated resource plan* represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed." The plain language of this provision indicates that the Commission is tasked with analyzing the Companies' proposed 2020 IRPs as total plans that include multiple portfolios. The Commission accordingly finds that the Companies' 2020 IRPs complied with the requirements of Act 62 by presenting six planning portfolios adjusted to different sensitivities. CCEBA's advocacy that the Companies must "pick a plan" is incorrect insofar as it fails to recognize that the IRP is a single plan comprised of multiple portfolios, as contemplated by the plain language of Act 62.

Viewing the six portfolios as a single integrated resource plan, the Commission finds that the 2020 IRPs reflect sophisticated modeling and analysis performed by individuals spanning multiple functional disciplines who collectively represent hundreds of years of industry experience. In addition, the Companies' response to ORS's recommendations, combined with the frequency with which the IRP filings are planned over the next several years gives the Commission confidence that the Companies' long term plans will continue to be refined over time.

The Commission also agrees with Witness Snider that resource planning assumptions are changing constantly as technology is developed and deployed and new laws and regulations are passed that impact the long-term costs and benefits of the Companies' resource plans. With this background and in view of the extensive testimony and evidence presented in this proceeding, the Commission finds that the six portfolios that make up the Companies' 2020 IRPs appropriately balance resource adequacy and capacity to serve anticipated peak electrical load, include reasonable planning reserve margins; consider consumer affordability and least cost; are designed to comply with applicable state and federal environmental regulations; power supply reliability; commodity price risks; diversity of generation supply, and other foreseeable conditions that the Commission determines to be for the public interest.

The Commission notes that the ORS has a unique role in representing the public interest by providing a balanced assessment of the reasonableness of these varying assumptions as it pertains to the requirements of Act 62 and the impact assumptions and outcome may have on consumers. The record also demonstrates that ORS approached its analysis from a technically objective and holistic perspective and without bias towards or against any specific technology or predetermined outcome from the resource planning process. Accordingly, ORS's support for the Companies' 2020 IRPs on the grounds that they are reasonable and prudent carries significant weight with the Commission. While the Commission is the ultimate fact-finder and is not beholden to the recommendations of ORS, we find the testimony proffered by ORS's witnesses in this case to be credible and reliable, and therefore useful to our decision-making in this proceeding.

The Commission further recognizes the Companies' efforts to address each of ORS's recommendations, often including a willingness to engage with stakeholders, including ORS, to inform development of the Companies' future IRPs. Recognizing that consensus among the parties is neither expected or required under Act 62, along with the frequency with which the Companies will make IRP filings over the next several years and the associated regulatory burden, their commitment to engage with the issues ORS raised should ensure future IRP filings are reasonable, refined and well-supported. For all of the foregoing reasons, the Commission finds that the Companies' 2020 IRPs comply with the requirements of Act 62. In sum, the Commission finds that the Companies' 2020 IRPs present the most reasonable and prudent plan to meet the Companies capacity and energy needs and should be approved under Act 62.

Finally, in the near term, the Commission agrees with the Companies and ORS that the Plan A Base Case Without Carbon is the Companies' least cost plan that reflects compliance with the legal and regulatory requirements in effect today and is the Companies "appropriate plan" for use in other proceedings, such as avoided cost and DSM/EE cost effectiveness. The Commission also finds that the Companies' Short Term Action Plans are reasonable for planning purposes based on the evidence presented by Witness Snider.

VII. ORDERING PARAGRAPHS

NOW, THEREFORE, IT IS HEREBY ORDERED THAT:

1. Based upon the Companies' 2020 IRPs, the testimony, exhibits received into evidence at the hearing, and the entire record of these proceedings, the Commission hereby adopts each and every Finding of Fact enumerated herein. The Commission's conclusions of law are fully stated above.

2. The Companies Motion to Strike, originally filed on April 19, 2021 and renewed in the Companies' Renewed Motion to Strike filed on June 9, 2021, is granted, and the pre-filed and live surrebuttal testimonies and corresponding exhibits of Rachel Wilson and John Wilson are hereby stricken from the record in their entirety.

3. Any motions not expressly ruled upon herein are denied.

4. The Commission approves the 2020 IRPs filed by DEC and DEC.

5. The Companies shall implement all commitments made in response to ORS's recommendations, as described in the Rebuttal Testimony of the Companies' witnesses, and as set forth in Table 1 and Table 2 of ORS Witness Hayet's Surrebuttal Testimony, which is also reproduced herein.

6. The Companies shall include a solar purchase power agreement ("PPA") resource option as a sensitivity to the Base with Carbon Policy portfolio and Base without Carbon Policy portfolio in the 2021 IRP Update.

BY ORDER OF THE COMMISSION:

____

Justin T. Williams, Chairman

ATTEST:

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Jocelyn Boyd, Chief Clerk/Executive Director